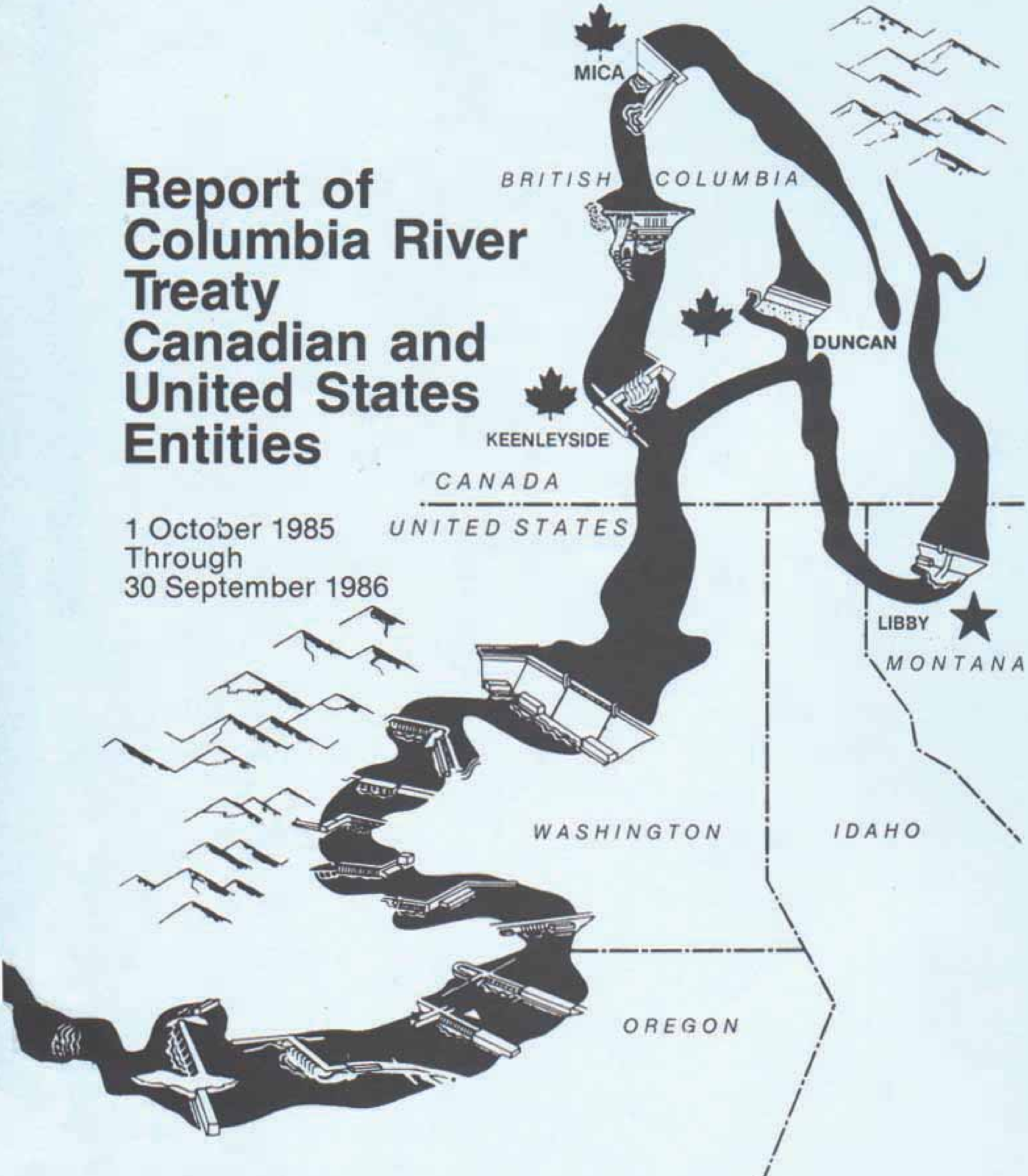
Report of Columbia River Treaty Canadian and United States Entities

1 October 1985
Through
30 September 1986



October 1986

United States Entity

Columbia River Treaty
P.O. Box 3621, Portland, Oregon 97208

Chairman:
Administrator
Bonneville Power Administration
Department of Energy

Member:
Division Engineer
North Pacific Division
Corps of Engineers
Department of the Army

n reply refer to: PRCA

December 16, 1986

MEMORANDUM

TO: Addressees

FROM: John M. Hyde, PE John M. Hyde
Secretary, United States Entity

SUBJECT: Distribution of Treaty Annual Reports and Operating Plans

Some or all of the following documents are attached for your information:

1. List of "Distribution of Columbia River Treaty Documents To Other Than Treaty Organization Individuals"

2. "Report of Columbia River Treaty, Canadian and United States Entities, for the Period 1 October 1985 to 30 September 1986," (Entity Report) describing the activities of the Entities and the operation of the Canadian storage under the Columbia River Treaty.

3. "Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1991-92," (AOP/DDPB) dated November 1986.

4. "Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1986 Through 31 July 1987," (DOP) dated October 1986.

Attachments

Addressees
R. Ratcliffe - A
S. Hickok - A
L. Johnson - AC
J. Robertson - AL
J. Luce/P. Majkut - APP
L. Larson - AR
T. Esvelt - OS
J. Jones - P
W. Pollock - P
J. McLennan - PG
S. Smith - PJI
S. Montfort - PRC
A. Evans - PRCA
M. Bauer - PRCA
D. Jones - PRCB
B. MacKay - PRCB
G. Tollefson - S
BPA Library - SSL
H. Brush - BUREC
H. Kasai - Consultant
J. Piska - Dg. Co. PUD
A. Chilingerian - ICP
J. Litchfield - NPPC
M. Hanson - NWPP
J. Frewing - PGE

DISTRIBUTION OF
COLUMBIA RIVER TREATY DOCUMENTS
TO OTHER THAN TREATY ORGANIZATION INDIVIDUALS

DISTRIBUTION	ENTITY REPORT	AOP/DDPB	DOP
Bob Ratcliffe - A	1		
Steve Hickok - A	1		
Lee Johnson - AC	1		
Jack Robertson - AL	1		
Jim Luce/Paul Majkut - APP	1	1	
Larry Larson - AR	1		
T. Esvelt - OS	1		
Jim Jones - P	1		
Walt Pollock - P	1		
Janet McLennan - PG	1		
Steve Smith - PJI	1		
Steve Montfort - PRC	1		
Art Evans - PRCA	1	1	
Mitzi Bauer - PRCA	1	1	
Diana Jones - PRCB	1		
Bruce MacKay - PRCB	1		
G. Tollefson - S	1		
BPA Library - SSL	2	2	2
Harold Brush - BUREC	1	1	1
Hugh Kasai - Consultant	1	1	1
Jim Piska - Douglas Co. PUD	1	1	1
Avo Chilingerian - ICP	1	1	1
Jim Litchfield - NPPC	1	1	1
Mike Hanson - NWPP	1	1	1
Jim Frewing - PGE	1	1	1

JHyde:cj (WP-PRC-2722G)

ANNUAL REPORT OF THE

COLUMBIA RIVER TREATY

CANADIAN AND UNITED STATES ENTITIES

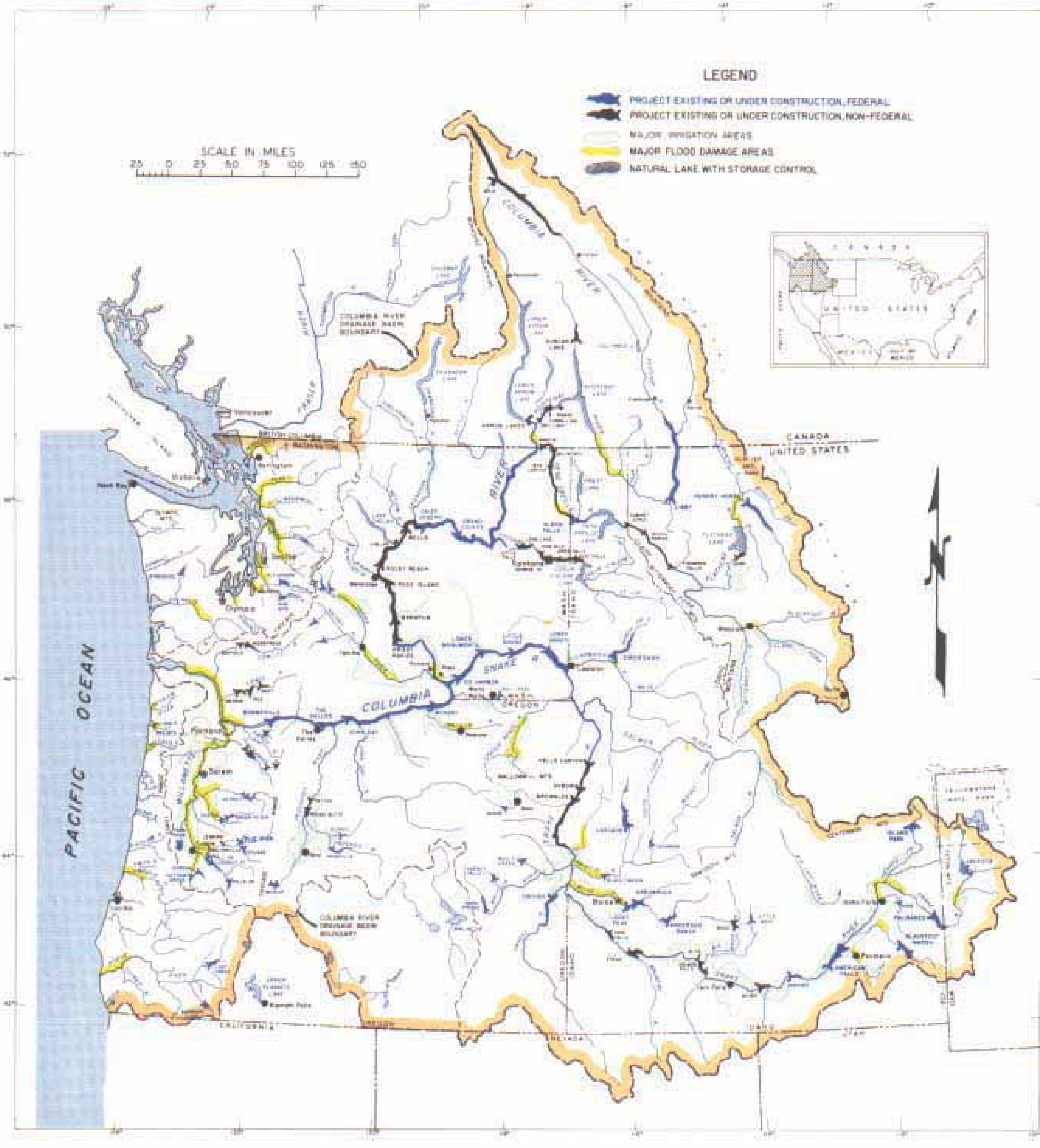
For the Period

1 October 1985

Through

30 September 1986

COLUMBIA RIVER AND COASTAL BASINS



EXECUTIVE SUMMARY

ENTITY

The chairmanship of the U.S. Entity changed on 18 July 1986 as Mr. James J. Jura succeeded Mr. Peter T. Johnson as Administrator of the Bonneville Power Administration.

Agreements approved by the Entities during the period of this report include:

- o Agreement relating to the preparation of the 1990-91 AOP and studies necessary to address the outstanding issues signed on 5 December 1985.
- o Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1990-91, dated November 1985.
- o Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1985 through 31 July 1986, dated October 1985.

As required by the 5 December 1985 Entity Agreement, the Operating Committee completed a number of studies during the year to determine the impact of several proposed changes to the Assured Operating Plan (AOP) and Determination of Downstream Power Benefits (DDPB). However, the Entities have not yet reached agreement on changed criteria for the AOP and DDPB computations. As a result, a traditional AOP for 1991-92 Operating Year is being prepared.

SYSTEM OPERATION

The coordinated system reservoirs filled to only 92% of capacity during the summer of 1985. This condition and low flows during the summer and fall months caused the reservoir system to proportionally draft below Operating Rule Curves (ORC). Above normal rainfall occurred in October and the actual level of the reservoir system filled to the ORC. December was cold and dry causing the reservoir system to return to proportional draft to meet system loads. About mid-February wet and warm weather caused streams to rise rapidly and the system to be operated for flood control. The Corps specified daily outflow requirements from Treaty projects between 23 February and 5 March to meet downstream flood control objectives. Following this event projects resumed their drawdown to provide spring flood control space. Streamflows remained below normal until late May when much-above-normal temperatures caused a rapid rise in streamflow. Most projects received daily flood control requests from 28 May to 20 June. Management of reservoir storage resulted in the flow and stage of the Columbia River being reduced to near zero damage level.

The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement, was 444 average megawatts at rates up to 1,134 megawatts from 1 August 1985 through 31 March 1986, and 418 average megawatts at rates up to 1,093 megawatts from 1 April 1986 through 31 July 1986. All CSPE power was used to meet Pacific Northwest loads during the period of this report.

PROJECT OPERATION

Mica Treaty storage account was full at the beginning of the period (1 October). The reservoir was drawndown to a low storage content of 1.22 maf. Water was spilled past the project beginning on 25 July to slow the refill rate and the reservoir was full, elevation 2475, by early August.

Arrow Reservoir started the period at elevation 1445, one foot above normal full level. It was drafted to meet flood control and power requirements reaching its lowest level, elevation 1399.6, on 7 May. Treaty storage space was refilled by 18 July 1986. The reservoir was about 5 feet below elevation 1444 during August and September to balance the water that was above normal Treaty storage in Mica.

Duncan Reservoir was about 20 feet below full pool at the beginning of the period and reached its lowest level, elevation 1807.5, on 21 April. The reservoir filled to full pool on 23 July 1986 and remained full through the rest of the period.

Libby Reservoir started the period near elevation 2444 after only filling to about 10 feet from full, elevation 2459, on 1 August 1985. During the period the reservoir was drawndown to elevation 2356. The reservoir filled to full pool, elevation 2459, on 20 July 1986 and remained near this level through August. On 1 October 1986 the reservoir was about 14 feet below full.

1986 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

CONTENTS

C O N T E N T S (Continued)

1986 REPORT OF THE COLUMBIA RIVER TREATY ENTITIES

I. INTRODUCTION

This annual Columbia River Treaty Entity Report is for the 1986 Water Year, 1 October 1985 through 30 September 1986. It includes information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during that period with additional information covering the reservoir system operating year, 1 August 1985 through 31 July 1986. The power and flood control effects downstream in Canada and the United States are described. This report is the twentieth of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is required to be operated for the purpose of increasing hydroelectric power generation, and for flood control in the United States of America and in Canada. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the North Pacific Division, Army Corps of Engineers (ACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 15.5 million acre-feet (maf) of usable storage. (This has been accomplished with 7.0 maf in Mica, 7.1 maf in Arrow and 1.4 maf in Duncan.)

2. For the purpose of computing downstream benefits the U.S. hydrolectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.

3. The U.S. and Canada are to share equally the additional power generated in the U.S. resulting from operation of the Canadian storage.

4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for expected flood control benefits in the U.S. resulting from operation of the Canadian storage.

5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage.

6. The U.S. constructed Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada made the land available.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses and, in addition, after September 1984 Canada has the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement Purchase Agreement of 13 August 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on 1 April 1968, at Arrow on 1 April 1969, and at Mica on 1 April 1973.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II. TREATY ORGANIZATION

ENTITIES

There was one meeting of the Columbia River Treaty Entities (including the Canadian Entity Representative and U.S. Coordinators) during the year on the morning of 5 December 1985 in Portland, Oregon. The members of the two Entities during the period of this report were:

UNITED STATES ENTITY

Mr. James J. Jura, Chairman
Administrator, Bonneville Power Administration
Department of Energy
Portland, Oregon

Major General George R. Robertson
Division Engineer,
North Pacific Division,
Army Corps of Engineers,
Portland, Oregon

CANADIAN ENTITY

Mr. Chester A. Johnson, Chairman
Chairman, British Columbia Hydro and Power Authority
Vancouver, B.C.

Mr. James J. Jura succeeded Mr. Peter T. Johson as Administrator of Bonneville Administration on 18 July 1986. Mr. Johnson had been Administrator of BPA and Chairman of the United States Entity since May 1981.

The Entities have appointed Coordinators and a Representative and two joint standing committees to assist in Treaty implementation activities. These are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.
2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services.
3. Operate a hydrometeorological system.
4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.

5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

7. The Treaty provides that the two governments may, by an exchange of notes, empower or charge the Entities with any other matter coming within the scope of the Treaty.

ENTITY COORDINATORS AND REPRESENTATIVE

The Entities have appointed members of their respective staffs to serve as coordinators or focal points on Treaty matters within their organizations. These are:

UNITED STATES ENTITY COORDINATORS

Edward W. Sienkiewicz, Coordinator
Asst. Administrator for Power and Resources Management
Bonneville Power Administration
Portland, Oregon

Herbert H. Kennon, Coordinator
Chief, Engineering Division
North Pacific Division
Army Corps of Engineers
Portland, Oregon

John M. Hyde, Secretary
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY REPRESENTATIVE

Douglas R. Forrest, Manager
Canadian Entity Services
B.C. Hydro and Power Authority
Vancouver, B.C.

ENTITY OPERATING COMMITTEE

The Operating Committee was established in September 1968 by the Entities and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

UNITED STATES SECTION	*CANADIAN SECTION*
Robert D. Griffin, BPA, Co-Chairman	Timothy J. Newton, BCH, Chairman
Nicholas A. Dodge, ACE, Co-Chairman	Ralph D. Legge, BCH
Russell L. George, ACE	William N. Tivy, BCH
John M. Hyde, BPA	Kenneth R. Spafford, BCH

Mr. George succeeded Mr. Gordon G. Green of the U.S. Section of the Operating Committee on 1 December 1985. Mr. Green retired from the Corps of Engineers on 6 January 1986 after a long career with Treaty related activities.

There were six meetings of the Operating Committee during the year. The dates, places and number of persons attending those meetings were:

Date	Location	Attendees
14 November 1985	Vancouver, B.C.	16
13 January 1986	Portland, Oregon	17
11 March 1986	Vancouver, B.C.	15
7 May 1986	Portland, Oregon	11
10 July 1986	Vancouver, B.C.	17
16 September 1986	Portland, Oregon	

The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report which has been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee completed the 1990-91 Assured Operating Plan (AOP) and Determination of Downstream Power Benefits (DDPB) and began preparations of the 1991-92 AOP/DDPB.

As required by 5 December 1985 Entity agreement, the Operating Committee completed a number of studies to determine the impact of several proposed changes the AOP and DDPB. A copy of the report will be submitted to the PEB.

ENTITY HYDROMETEORLOGICAL COMMITTEE

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	*CANADIAN SECTION*
Roger G. Hearn, BPA, Co-Chairman (Retired June 1986)	Ulrich Sporns, BCH, Chairman (Retired January 1986)
Douglas D. Speers, ACE, Co-Chairman	John R. Gordon, BCH, Member

The Hydrometeorological Committee held no meetings during the year, but remained in communication by telephone to address any data exchange problems that developed and to discuss other business of the Committee. In general, data exchanged went smoothly and a few minor problems were quickly corrected.

The Committee submitted a revised version of the Hydrometeorological Documents Report to the Permanent Engineering Board in November 1985, and this received the approval of the Board at their annual meeting. During the year, maps depicting the location of Treaty and Support Facility stations were prepared and were furnished to holders of the Hydrometeorological Documents Report.

An advancement in data exchange was achieved this year with the installation of the Corps of Engineers of a GOES satellite downlink in Portland. This will enable both Canadian and United States satellite stations to be reported directly to the CROHMS central computer rather than having it relayed to Portland via other communication channels and through other agencies.

PERMANENT ENGINEERING BOARD

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. The members of the PEB are presently:

UNITED STATES SECTION	*CANADIAN SECTION*
Lloyd A. Duscha, Chairman, Washington, D.C.	G. M. MacNabb, Chairman Ottawa, Ontario
J. Emerson Harper, Member Washington, D.C.	B. E. Marr, Member Victoria, B.C.
Alex Shwaiko, Alternate Washington, D.C.	H. M. Hunt, Alternate Victoria, B.C.
Thomas L. Weaver, Alternate Golden, Colorado	E. M. Clark, Alternate & Secretary
S. A. Zanganeh, Secretary Washington, D.C.	

In general, the duties and responsibilities of the PEB are to assemble records of flows of the Columbia River and the Kootenay River at the international boundary; report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action; assist in reconciling differences that may arise between the Entities; make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met; make an annual report to both governments and special reports when appropriate; consult with the Entities in the establishment and operation of a hydrometeorological system; and, investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream benefit computations, hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the Permanent Engineering Board and the Entities was held on the afternoon of 5 December 1985 in Portland, Oregon. Differences between the two Entities and the PEB on how to prepare AOPs and determine downstream power benefits for the future were discussed at this meeting.

PEB ENGINEERING COMMITTEE

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM are presently:

UNITED STATES SECTION

S. A. Zanganeh, Acting Chairman
Washington, D.C.
Gary L. Fuqua, Member
Portland, Oregon
Larry C. Larson, Member
Washington, D.C.

CANADIAN SECTION

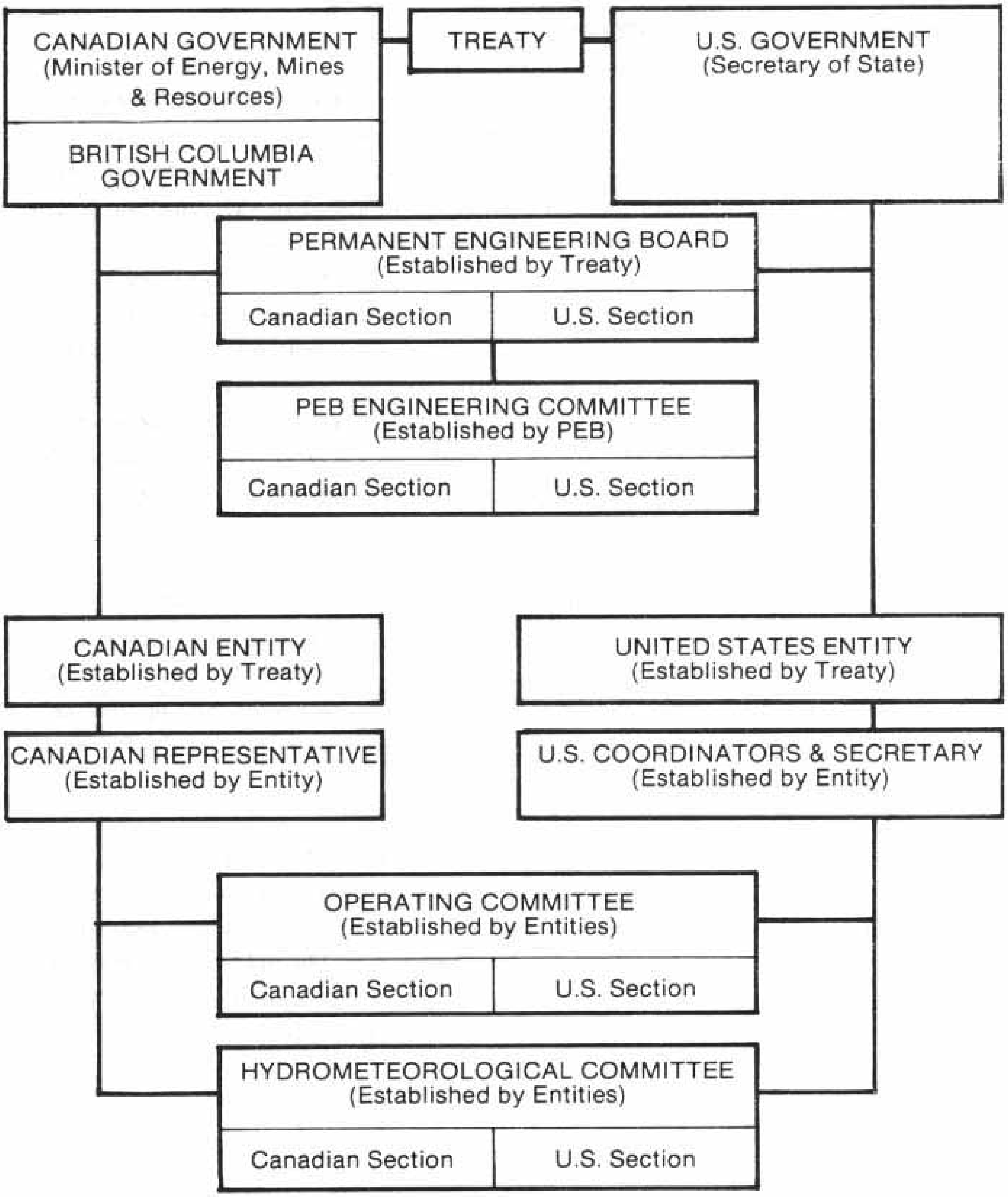
R. O. "Neil" Lyons, Chairman
Vancouver, B.C.
David B. Tanner, Member
Victoria, B.C.

INTERNATIONAL JOINT COMMISSION

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If a dispute concerning the Columbia River Treaty could not be resolved by the Entities or the PEB it would probably be referred to the IJC for resolution before being submitted to a tribunal for arbitration.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC currently informed. There are four such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, the International Osoyoos Lake Board of Control and the International Skagit River Board of Control. The Entities and their committees conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

COLUMBIA RIVER TREATY ORGANIZATION



III. OPERATING ARRANGEMENTS

POWER AND FLOOD CONTROL OPERATING PLANS

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans and that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not be adverse to the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans five years in advance to furnish the Entities with an Assured Operating Plan for Canadian storage. In addition, Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce more advantageous results through the use of current estimates of loads and resources. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated May 1983 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to plan and operate Treaty storage during the period covered by this report. These documents were previously approved by the Entities.

The planning and operation of Treaty Storage as discussed on the following pages is done for the operating year, 1 August through 31 July. The planning and operating for U.S. storage operated according to the Pacific Northwest Coordination Agreement is done for a slightly different operating year, 1 July through 30 June. Therefore, most of the hydrographs and reservoir charts in this report are for a 13 month period, July 1985 through July 1986.

ASSURED OPERATING PLAN

The Assured Operating Plan (AOP) dated September 1980 established Operating Rule Curves for Duncan, Arrow and Mica during the 1985-86 operating year. The Operating Rule Curves provided guidelines for refill levels as well as drawdown levels. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1983 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972.

DETERMINATION OF DOWNSTREAM POWER BENEFITS

For each operating year, the determination of downstream power benefits resulting from Canadian Treaty storage is made five years in advance in conjunction with the Assured Operating Plan. For operating years 1984-85 and 1985-86 the estimates of benefits resulting from operating plans designed to achieve optimum operation in both countries were less than that which would have prevailed from an optimum operation in the United States only. Therefore, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement, the Entities agreed that the United States was entitled to receive 3.5 average megawatts of energy during the period 1 August 1985 through 31 March 1986, and 4.5 average megawatts of energy during the period from 1 April through 31 July 1986. Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy. Computations indicated no loss or gain in dependable capacity during the 1985-86 operating year.

DETAILED OPERATING PLAN

During the period covered by this report, storage operations were implemented by the Operating Committee in accordance with the "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated October 1985. The DOP established criteria for determining the Operating Rule Curves for use in actual operations. Except for minor changes at Arrow, the DOP used the AOP critical rule curves for Canadian projects. The Canadian Entity agreed to lower the Arrow first year October through December critical rule curve and to raise the February and April critical rule curve to improve the hydro regulation in the 1985-86 Pacific Northwest Coordination Agreement operating plan. The Variable Refill Curves and flood control requirements subsequent to 1 January 1986 were determined on the basis of seasonal volume runoff forecasts during actual operation. The regulation of the Canadian storage was conducted by the Operating Committee on a weekly basis except when flood control requirements necessitated daily regulation.

ENTITY AGREEMENTS

During the period covered by this report, three agreements were officially approved by the Entities. The following tabulation indicates the date each of these were signed or approved and gives a description of the agreement:

Date Agreement Signed by Entities	Description
5 December 1985	Agreement relating to the preparation of the 1990-91 AOP and studies necessary to address the outstanding issues.
5 December 1985	Columbia River Treaty Assured Operating Plan and Determination of Downstream Power Benefits for Operating Year 1990-91, dated November 1985.
5 December 1985	Detailed Operating Plan for Columbia River Treaty Storage, 1 August 1985 through 31 July 1986, dated October 1985.

LONG TERM NON-TREATY STORAGE CONTRACT

In accordance with the 9 April 1984 Entity Agreement which approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement, the Operating Committee monitored the storage operations made under the agreement to insure that they did not adversely impact operation of Treaty storage required by the Detailed Operating Plan.

IV. WEATHER AND STREAMFLOW

WEATHER

Chart 1 is a geographical illustration of the seasonal precipitation in percent of normal for the 1 October 1985 through 31 March 1986 period in the Columbia River Basin. Chart 2 shows an index of the accumulated snowpack in the Columbia Basin above The Dalles in percent of normal for the 1 January through 1 May 1986 period. Indices of temperature and precipitation in the Columbia Basin are shown on charts 3, 4, and 5 for the 1 September 1985 to 31 August 1986 period. The following paragraphs describe significant weather factors from 1 August 1985 to 30 September 1986. In this report temperatures are given in degrees Fahrenheit.

The fall (September-November) season in the Pacific Northwest was generally cooler and wetter than normal. September temperatures were 3° to 10°F below normal and precipitation ranged from 108 to 341 percent of normal. For the basin above The Dalles precipitation averaged 206 percent of normal. October continued cold and wet with regional temperatures averaging as much as 6°F below monthly normal. Most of the October storms went through the northern part of the basin as indicated by the precipitation distribution which averaged 168 percent of normal in the basin above Grand Coulee and 152 percent in the basin above The Dalles. November began with a brief warm, wet spell, but by the 10th, a large high pressure system over northwestern Canada pushed very cold artic air into the basin dropping monthly regional temperatures to 20° to 34°F below normal. This cold spell, which persisted to month's end, was supplemented by surface weather features which brought moist air into the region. The result was periodic snow storms over the entire region, even in western valleys, during the last half of the month. Despite the low temperatures total monthly precipitation averaged 95 percent of normal above The Dalles.

The winter season was a turn-around in weather even though December was a continuation of the fall cold spell. Like November, the first week of December was a respite from the cold with temperatures rising to near normal between the

3rd and 9th. When the high pressure system re-established extended periods of fog occurred in many areas. Because this air mass was dry and stable it only produced 30 percent of normal precipitation for December in the basin above The Dalles. At the beginning of January the off shore ridge of high pressure was replaced by a low pressure trough which fed a constant supply of moist warm air to the Pacific Northwest. This produced thawing of ice jams and melting of low level snowpacks which reached its zenith about mid-month. Average monthly temperatures varied from 12°F above normal at Cranbrook, British Columbia to 1°F below normal at Twin Falls, Idaho. Despite this large temperature gradient precipitation averages for the basin above Grand Coulee and above Ice Harbor were similar, 83 and 75 percent, respectively. February began with a moderate storm passing through the region. This was followed by the development of an offshore ridge which was similar to that of December and January. After a week this ridge moved north allowing very warm and moist air from Hawaii to produce very heavy rainfall and low elevation snowmelt in the southern portions of the Columbia/Snake basins. Temperatures averaged 3° to 10°F above normal while monthly precipitation in the Snake averaged 246 percent of normal and for the basin above The Dalles it averaged 185 percent.

March weather presented a varied pattern with ridge conditions predominating over the Pacific Northwest at the start and at the end of the month. Temperatures averaged 5° to 9°F above normal across the basin, with maximums 21°F above normal. Precipitation for the basin averaged 92 percent of normal.

During April a low pressure trough off the Pacific coast which kept re-establishing itself controlled the month's weather. Although monthly temperatures averaged near normal the first ten days of April were much warmer than normal while the last 20 were below normal. The basin above The Dalles averaged 105 percent of normal monthly precipitation.

Three major storm systems passed through the basin during May producing precipitation that averaged 105 percent of normal. The coldest of these produced heavy snowfall in the mountainous regions on the 8th. By the month's end the weather had warmed and several new maximum monthly temperatures records were set throughout the basin. The warm weather at the end of May continued for the first week in June. Temperatures were as much as 20°F above normal during this period. Basin precipitation averaged only 77 percent of normal for the month.

During July, sedentary low pressure system produced cool temperatures, as much as 25°F below daily normal, and above normal precipitation. The index of precipitation in the basin above Castlegar, British Columbia, was 163 percent of normal while the basin above The Dalles averaged 143 percent of normal. At the beginning of August the weather pattern abruptly changed as the area came under the domination of a high pressure ridge. This produced little rain and temperatures nearly 10 degrees above normal.

The final precipitation index figure for the Columbia Basin above The Dalles each month differs from the preliminary precipitation index figure. The preliminary index is computed daily based on 16 usually representative stations. The final index is based on 60 stations and is computed at the end of each month after all the data are collected. There is usually some slight difference between the preliminary and the final monthly precipitation figures. The following tabulation shows the 20-year average (1961-1980) monthly precipitation in the Columbia Basin above The Dalles as compared to the final and the preliminary (prelim) indices for water year 1986 (WY 86).

Month	20-Year Average (in.)	WY 86 Indices Final (%)	WY 86 Indices Prelim (%)	Month	20-Year Average (in.)	WY 86 Indices Final (%)	WY 86 Indices Prelim (%)
Oct '85	1.76	159	136	Apr '86	1.61	106	114
Nov '85	2.71	93	84	May '86	1.75	102	103
Dec '85	3.29	33	24	Jun '86	1.84	82	84
Jan '86	3.33	87	73	Jul '86	0.96	146	151
Feb '86	2.15	188	154	Aug '86	1.29	54	34
Mar '86	1.91	93	84	Sep '86	1.41	187	178

STREAMFLOW

The observed inflow and outflow hydrographs for the period 1 July 1985 to 31 July 1986 are shown on charts 6 through 9 for the four Treaty reservoirs. Observed flows with the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee and The Dalles are shown on charts 10, 11, 12, and 13, respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 1986 period including one that would have occurred if regulated only by the Treaty reservoirs. The following paragraphs describe significant streamflow events from the summer of 1985 through September 1986.

During August 1985 streamflow in the Pacific Northwest was generally near normal to well below normal in reflection of dry summer weather. Heavy September precipitation increased soil moisture so that the streamflow pattern through November was well above normal. A two-month cold spell began mid-November. This gradually reduced flows to well below normal during December. Ice jamming in the upper and middle Snake Basins resulted from this cold. Although January was slightly warmer than normal and a normal amount of precipitation fell throughout the month, it was not adequate to warm and prime the snowpack to produce normal streamflows.

Well above normal precipitation in February, coupled with the year's first warm spell, which lasted into mid-April, produced well above normal streamflows. Weather patterns changed abruptly in mid-April, causing temperatures to well below normal for the next six weeks. This curtailed snowmelt in the Canadian portion of the basin so that streamflows fell to normal or below. Despite this cooling, streamflows in the southern subbasins remained above normal.

A 10-day hot spell, which began the last week in May, produced the seasonal high discharges in the northern basins. Even with this accelerated discharge the streamflows for June averaged slightly less than normal. Despite the cool wet weather of July the summer streamflows remained slightly below normal.

The 1985-86 monthly modified streamflows and the average monthly flows for the 1929-1978 period are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These modified flows have been corrected for storage in lakes and reservoirs to exclude the effects of regulation, and are adjusted to the 1980 level of development for irrigation.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Modified Flow 1985-1986	Average 1929-1978	Modified Flow 1985-1986	Average 1929-1978
Aug '85	71,440	103,142	98,820	139,054
Sep '85	59,450	64,457	97,840	97,214
Oct '85	56,420	50,650	98,750	87,349
Nov '85	60,310	45,525	103,700	89,536
Dec '85	33,310	43,793	68,210	95,166
Jan '86	33,620	38,482	81,770	91,901
Feb '86	52,050	41,045	166,800	102,817
Mar '86	100,400	50,359	262,300	122,728
Apr '86	116,000	117,432	251,300	221,814
May '86	231,900	272,024	393,000	421.758
Jun '86	301,800	325,692	456,500	479,654
Jul '86	154,900	195,586	195,500	216,610
YEAR	106,098	112,678	189,275	180,649

SEASONAL RUNOFF FORECASTS AND VOLUMES

Observed 1986 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-80 Average
Libby Reservoir Inflow	6,099	92
Duncan Reservoir Inflow	2,103	101
Mica Reservoir Inflow	11,897	102
Arrow Reservoir Inflow	23,358	99
Columbia River at Birchbank	39,561	96
Grand Coulee Reservoir Inflow	54,113	86
Snake River at Lower Granite Dam	23,949	102
Columbia River at The Dalles	85,285	90

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1986 as usual for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the seasonal volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects and for the unregulated runoff for the Columbia River at The Dalles. Also shown in table 1 are the actual volumes for these five locations. The forecasts for Mica, Arrow and Duncan inflow were prepared by B.C. Hydro and those for the lower Columbia River and Libby inflows were prepared by the United States Columbia River Forecasting Service.

The 1 April 1986 forecast of January through July runoff for the Columbia River above The Dalles was 106.0 maf and the actual observed runoff was 108.3 maf, only a 2 percent differential. The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared to the actual runoff measured in millions of acre-feet (maf):

Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	82.5	99.5	93.4	94.3	95.1	--	95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	135.0	140.0	146.0	149.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.7	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3

V. RESERVOIR OPERATION

GENERAL

The operating year began with the coordinated reservoir system officially filled to only 92 percent of capacity. An unusually dry summer resulted in the U.S. system being proportionally drafted to meet firm energy loads beginning in early July. Several measures were, however, taken during the summer to reduce the amount of required draft. BPA began receiving energy from B.C. Hydro, as well as several private and public utilities, under a special storage agreement. In addition, the Boardman coal-fired powerplant was brought into service for the summer. Also, BPA delayed the sale of some surplus firm energy. The reservoir system operated on proportional draft through October when a series of rainstorms helped the actual level of the the system recover back to the normal base energy content curve (BECC).

The reservoir system continued drafting for flood control and power through the autumn months. Colder than normal weather in late November caused a significant increase in the system draft rate. Unseasonably dry weather in December again forced the U.S. system into proportional draft to serve firm loads. Although water supply forecasts for 1 January were generally below average, some draft in January for flood control still was necessary at most projects. Tables 1 through 5 show the monthly January through June 1986 volume runoff forecasts and VECC computations for the Treaty projects.

Beginning in mid-February a major change in weather conditions occurred throughout much of the lower Columbia and Snake River drainage basins. A series of unseasonably warm and wet weather systems triggered rapid rises in streamflow with rivers at several control points exceeding bankfull conditions and, in some cases, flood stage. As a result, the reservoir system was regulated on a daily basis for flood control between 23 February and 5 March. Releases from Arrow, Duncan and Libby were all reduced essentially to minimum for much of this period. Outflows from these projects were all increased after this event to provide the necessary space for control of the snowmelt freshet.

Treaty project inflows began rising in April but increases were moderate until mid-May when high temperatures triggered a rapid rise in streamflow throughout the entire basin. The reservoir system began being regulated on a daily basis for flood control on 28 May as the flow in the lower Columbia River was near the initial controlled flow. Operation of some reservoirs for flood control continued until 25 June. The extremely warm temperature sequence of mid- and late May resulted in an especially high unregulated flow considering the less-than-average observed runoff for the April to August period. The coordinated reservoir system was more than 98 percent full on 31 July and was therefore, officially declared full for Coordination Agreement purposes. Unseasonably dry weather throughout the summer months forced the U.S. system into proportional draft to meet firm power loads beginning in mid-August 1986. This proportional draft continued throughout September.

In 1986 the U.S. reservoir system was again operated to provide flows for the downstream migration of juvenile anadromous fish. The 3.45 maf Water Budget for Priest Rapids was fully utilized between 5 May and 1 June with natural flows then providing good passage conditions in June. The weekly average outflow from Priest Rapids exceeded the 130,000 cfs flow desired for fish passage between 1 April and 15 June.

MICA RESERVOIR

As shown in Chart 6, the Treaty storage space at Mica reservoir was completely refilled on 25 July 1985. The actual level on that day was only elevation 2453.0 feet as some of the non-Treaty storage space was not quite full. Between 1 August and 21 September, the Treaty storage account at Mica was maintained full, but because of operations involving the other non-Treaty storage accounts, the reservoir was actually drafted slightly to elevation 2451.9 feet by 21 September. Inflow into Mica reservoir dropped below its minimum discharge of 10,000 cfs in late September, causing a slight draft of the Treaty storage account as per the Detailed Operating Plan (DOP). During the autumn months, Treaty storage continued to draft per the DOP release schedule. As a result, the reservoir was drafted to its Operating Rule Curve elevation of 2425.2 feet by 31 December after adjusting for deficits in the non-Treaty storage accounts at Mica. The project outflows during this period varied between 5,000 cfs and 40,000 cfs.

Because the Arrow reservoir level was lower than normal in December, the Treaty storage release target at Mica in January was revised from 25,000 cfs to 30,000 cfs as per DOP, thus accelerating the reservoir drawdown in January. By 27 February, Mica reservoir was drafted to elevation 2401.7 feet, its lowest level for the current operating year. The Treaty storage account continued to draft through March and April, due to inflows lower than the DOP targets for those months. However, because of the filling of the non-Treaty storage accounts, the actual level at Mica was increased during this period. The Treaty storage account was at its lowest level, 616.3 ksfd (1.22 maf), on 3 May 1986.

Inflows into Mica reservoir were well below normal in April and early May. However, inflows increased to above the DOP target outflow of 10,000 cfs after 3 May and the Treaty storage account at Mica began to fill. Actual powerhouse discharges varied between zero on the weekends and approximately 5,000 cfs during weekdays in this period. The warm weather in the latter part of May and early June caused the inflow to rise quickly, peaking at 108,490 cfs on 1 June. Inflows then receded to average in June and July but the reservoir continued to fill quickly. The Treaty storage account was refilled by 10 July 1986. The actual elevation at Mica was 2466.9 feet on that day. Due to inflows exceeding the powerhouse hydraulic capacity and, occasionally, B.C. Hydro's system load requirements, Mica reservoir continued to fill towards its normal full pool elevation 2475.0 feet. On 25 July, the project began spilling to reduce the rate of fill and on 10 August, the project was up near full pool.

The Treaty storage account is expected to remain full until 30 September. However, return of the non-Treaty storages from Mica to BPA or B.C. Hydro caused the actual reservoir level to draft slightly to elevation 2472.6 feet by 31 August 1986 and elevation 2466.4 feet by 30 September.

REVELSTOKE RESERVOIR

Revelstoke reservoir basically discharged inflows during this past operating year, operating within 5 to 10 feet of full pool. Spillway tests were conducted on 11 August and on 13 and 14 August 1986. The project is expected to continue to discharge inflows and will be operated within the 5 to 10 feet of its normal full pool elevation of 1880.0 feet.

ARROW RESERVOIR

As shown in Chart 7, Arrow reservoir was only filled to elevation 1434.5 feet by 1 July 1985, due to below average runoff in the summer months. This was approximately 10 feet below its normal full pool elevation of 1444.0 feet. Arrow reservoir resumed filling on 19 July and gradually filled through August and September. The reservoir continued filling into non-Treaty storage, reaching elevation 1445.8 feet 6 October.

Draft of Treaty storage began soon afterwards and by 31 October Arrow was drafted to its flood control level, elevation 1442.0 feet. The cold weather in November caused the Treaty storage at Arrow reservoir to be drafted heavily in November and December to elevation 1424.0 feet by 31 December after adjusting for the non-Treaty storage at Arrow. This was below the elevation 1426.8 feet that would trigger higher Treaty storage release from the Mica project in the following month. The reservoir continued drafting heavily in early January with the project outflows increased up to 89,000 cfs. Between 23 January and 5 February, the reservoir filled to elevation 1415.0 feet, before it resumed drafting again to meet power and flood control requirements. Between 23 February and 6 March, Arrow reservoir outflow was reduced to as low as 10,000 cfs to mitigate flood control problems caused by heavy rains. By 31 March, Arrow was drafted to elevation 1401.0 feet, slightly above its Flood Control Rule Curve, after adjusting for the non-Treaty storage at the Arrow reservoir. By 7 May, Arrow had drafted to elevation 1399.6 feet, its lowest level for the current operating year.

Arrow reservoir remained near elevation 1400.0 feet through 31 May before the project discharge was reduced to its minimum discharge of 5,000 cfs. Capturing the high runoff, which peaked at approximately 120,930 cfs on 31 May, caused the reservoir to fill rapidly through June and July. By 18 July, Arrow had filled to elevation 1443.4 feet, and the Treaty storage account at Arrow was considered full on that day, even though some of the Arrow storage was retained at Revelstoke reservoir to reduce spill in B.C. Hydro's system. Because of this, Arrow reservoir was drafted in July and August to as low as elevation 1438.0 feet. By 31 August, Arrow had filled to elevation on 1440.4 feet.

DUNCAN RESERVOIR

As shown in Chart 8, Duncan reservoir had only filled to elevation 1886.5 feet by 13 July 1985, due the well-below-average inflows during the summer months. The reservoir was then maintained at near elevation 1885.0 feet until early August.

During the period 16 August until 18 September, the reservoir was drafted, with the project outflow increased up to 10,000 cfs, to meet Treaty storage requirements. The reservoir was at elevation 1870.7 feet on 18 September. During the period from 29 September until 6 December, Duncan project discharge was generally maintained at its minimum level, 100 cfs, and the reservoir filled approximately 10 feet to elevation 1880.6 feet by 6 December. The outflow was increased above the minimum outflow on 7 December and the reservoir resumed drafting. With the project outflow varying between 5,000 cfs and 10,000 cfs, Duncan continued drafting through mid-February 1986.

Beginning 23 February, heavy rains produced high runoff in the lower Columbia River basin and Duncan outflow was reduced to as low as 100 cfs for flood control. The project discharge was increased again to 4,000 cfs on 7 March then reduced to 1,000 cfs on 10 March. During the remainder of March, Duncan was maintained near elevation 1811.0 feet, slightly above its flood control requirement of elevation 1807.8 feet.

Beginning 10 April, the discharge was again increased to as high as 5,000 cfs and the reservoir drafted to elevation 1807.5 feet by 21 April, its lowest level for the current operating year.

Inflows into the reservoir were below normal in early May and the project passed inflow, maintaining its level near elevation 1808.0 feet through 11 May. The reservoir began filling on 12 May when the outflow was reduced to the project minimum of 100 cfs. A warm spell in late May and early June caused the inflows to rise rapidly, peaking at 23,770 cfs on 29 May 1986. Capturing this high runoff, Duncan reservoir filled quickly through June and July. The project was filled to its normal full pool elevation 1892.0 feet by 23 July 1986.

The project then discharged inflow throughout the summer and was at elevation 1891.9 feet on 31 August 1985.

LIBBY

On 31 July 1985 Lake Koocanusa was at elevation 2449.5 feet, 9.5 feet below normal full pool. The lake did not fill in 1985 because much below normal precipitation occurred during the last months of the forecast period. The lake could, however, have filled higher than its highest elevation, 2449.9 feet, but proportional draft required the project pass inflow beginning in mid-July. The project continued releasing inflow in August and then drafted slightly in September to elevation 2443.3 feet on 30 September.

The lake continued drafting throughout the autumn with an average discharge of 18,700 cfs in October and November. By 30 November 1985 the lake elevation was 2405.6 feet, approximately 43 feet below the 1 December flood control requirement. On 6 December 1985 there was a railroad bridge failure and train derailment at the town of Bonners Ferry. Union Pacific Railroad representatives requested reduced Libby outflows to assist them in removing the derailed cars and bridge structure from the Kootenai River. Therefore, the project outflow was reduced to 4,000 cfs between 8 and 21 December. The average December outflow was approximately 13,500 cfs. The lake elevation was

2387.2 on 31 December 1984, approximately 21 feet below the 1 January base energy content curve (BECC) and approximately 24 feet below the 1 January flood control elevation. The lake was drawn below the BECC because the U.S. system was being proportionally drafted to meet coordinated system firm loads. The proportional draft point for Libby was 2391.6 feet and with BPA serving advanced energy the reservoir could have been drafted to elevation 2378.5 feet.

The project continued discharging high flows through January averaging approximately 17,000 cfs. The 31 January elevation was 2356.2 feet. This elevation was approximately 20 feet below the 31 January flood control and approximately one foot below the end of month VECC. The project outflow was then reduced to 4,000 cfs in February and held at that level until mid-March where it was increased to inflow to keep the lake elevation near its mid-March flood control requirement. In late April the outflow was reduced to 3,000 cfs when calculations showed there was only a 90% chance of refilling at 4,000 cfs.

Inflow began increasing to Lake Koocanusa in late May reaching 83,400 cfs on 31 May which was the peak for the year. This was the highest peak inflow since 1974 and about equal to 1972. Inflows continued to be high into June, with the lake filling at the rate of approximately 3 feet per day. Therefore, the outflow was increased to 10,000 cfs on 4 June. The outflow averaged 11,000 cfs in June and the lake filled approximately 35 feet reaching elevation 2457.0 feet on 30 June. The spring flood control and refill operation reduced the peak stage of the Kootenai River at the town of Libby by nearly 14 feet. At Bonner's Ferry, Idaho, the peak stage was reduced by 22 feet. The lake reached normal full pool 2459 feet on 20 July and basically passed inflow through the summer. In September the discharge was increased to draft the reservoir as the reservoir system began operating in accordance with proportional draft requirements.

KOOTENAY LAKE

As shown in Chart 10, Kootenay Lake filled to its peak level of 1747.3 feet on 3 June 1985. The lake was then drafted to elevation 1743.3 feet on the Nelson gage by 6 July. Inflow was then passed and the lake level maintained about elevation 1743.0 feet through August.

Kootenay Lake began filling towards its normal maximum operating level of elevation 1745.32 feet in September with the discharge controlled to between 15,000 cfs and 23,000 cfs. On 28 October, Kootenay Lake had filled to its maximum level due to high runoff produced by heavy rainfall. As a result, the discharge was increased to as high as 44,000 cfs on that day. During the period from November until December 1985, Kootenay Lake basically discharged inflows, maintaining the lake level near elevation 1745.0 feet.

Following the International Joint Commission (IJC) Rule Curve, Kootenay Lake began drafting in early January 1986. This continued through February and March and by 28 March the lake was drafted to elevation 1739.5 feet, its lowest level for the current operating year.

Kootenay Lake began discharging free flow on 4 March. Kootenay Lake continued to discharge free flow except for a short period of time when the discharge was reduced to facilitate inspection of the Kootenay Canal on 23 April. Capturing the early runoff, Kootenay Lake gradually filled to elevation 1741.0 feet by May 15. Heavy runoff in the latter part of May and early June caused the lake to rise rapidly to a peak elevation of 1748.7 feet on 6 June.

The runoff then receded in June and July enabling Kootenay Lake to be drafted to below elevation 1743.32 feet, its normal summer level by 4 August. On 31 August, the lake was at elevation 1743.4. In September, the lake was filled towards its normal winter operating level of elevation 1745.3 feet.

VI. POWER AND FLOOD CONTROL ACCOMPLISHMENTS

GENERAL

During the period covered by this report, Duncan, Arrow, Mica, and Libby reservoirs were operated in accord with the Columbia River Treaty. More specifically the operation of the reservoirs was in accordance with:

1. "Columbia River Treaty Hydroelectric Operating Plan - Assured Operating Plan for Operating Year 1985-86," dated September 1980.
2. "Detailed Operating Plan for Columbia River Treaty Storage - 1 August 1985 through 31 July 1986," dated October 1985.
3. "Columbia River Treaty Flood Control Operating Plan," dated October 1972.

Consistent with all Detailed Operating Plans prepared since the installation of generation at Mica, the 1985-86 Detailed Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty. The 1985-86 Assured Operating Plan prepared in 1980, was used as the basis for the preparation of the 1985-86 Detailed Operating Plan.

POWER

The Canadian Entitlement to downstream power benefits from Duncan, Arrow and Mica for the 1985-86 operating year had been purchased in 1964 by the Columbia Storage Power Exchange (CSPE). In accordance with the Canadian Entitlement Exchange Agreement dated 13 August 1964, the U.S. Entity delivered capacity and energy to the CSPE participants.

The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange Agreement was 444 average megawatts at rates up to 1,134 megawatts from 1 August 1985 through 31 March 1986, and 418 average megawatts at rates up to 1,093 megawatts from 1 April 1986 through 31 July 1986. All CSPE power was used to meet Pacific Northwest loads during the period of this report.

The coordinated reservoir system was 92 percent full on 1 August 1985 and after being drawn down during the 1985-86 operating year, recovered to near full on 31 July 1986. The following table shows the status of the energy stored in the coordinated system in billions of kilowatt-hours at the end of each month compared to rule curves during the 1985-86 operating year:

Month	Rule Curves	Actual	Difference
Aug '85	46.3	42.2	-4.1
Sep '85	42.9	40.8	-2.1
Oct '85	39.0	39.0	0.0
Nov '85	36.2	35.2	-1.0
Dec '85	31.9	28.3	-3.6
Jan '86	18.2	24.9	6.7
Feb '86	15.1	22.8	7.7
Mar '86	9.5	21.5	12.0
Apr '86	15.0	21.0	6.0
May '86	23.8	30.6	6.8
Jun '86	38.5	43.6	5.1
Jul '86	46.4	46.0	-0.4

NOTE: During the January-June period of 1986, volume runoff forecasts to cyclic reservoirs were sufficient to lower the operating rule curves below the assured refill curves.

The following table shows BPA non firm and surplus firm sales in megawatt-hours to Northwest and Southwest utilities during the 1985-86 operating year.

	To Northwest Utilities		To Southwest Utilities	
Period	Nonfirm	Surplus Firm	Nonfirm	Surplus Firm
Aug '85	0	17,600	0	1,112,280
Sep '85	0	29,840	0	1,364,281
Oct '85	0	19,570	0	749,449
Nov '85	275	158,042	126,497	1,022,255
Dec '85	0	75,217	0	1,016,837
Jan '86	0	15,140	0	204,201
Feb '86	189,203	16,000	712,009	353,428
Mar '86	1,306,348	15,510	797,556	68,704
Apr '86	1,973,111	12,500	918,450	49,645
May '86	2,233,150	400	979,187	0
Jun '86	1,518,335	7,020	919,464	279,180
Jul '86	828,779	0	1,343,216	676,246
TOTAL	8,049,201	336,839	5,796,379	6,896,506

During the 12 months ending 31 March 1986, B.C. Hydro sold a total of 42.26 million MWh electricity including exports of 9.40 million MWh of surplus electricity.

FLOOD CONTROL

The Columbia reservoir system including Treaty projects in Canada was operated on a daily basis for flood control in both late February to control runoff from heavy winter rainfall and again during the spring to control the annual spring freshet.

In late February and early March a series of unseasonably warm and wet weather systems caused rapid streamflow rises in the lower Columbia tributary basins and the Snake River basin. Daily flood control instructions were issued by teletype between 23 February and 5 March. Chart 14 shows the observed and unregulated flows at The Dalles during this period as well as the flow which would have occurred if regulated only by Treaty projects.

From this chart it can be seen that the Treaty projects were all drafting at the onset of this change in weather conditions. Although the discharges at all four projects were essentially reduced to minimum, operation of these projects did little to reduce stages in the lower Columbia River for several reasons. Natural flows in the upper river were relatively low and unaffected by the weather conditions that produced the rapid streamflow rises in the lower basin. In addition, Arrow was drafting rapidly with an outflow 70,000 cfs at the onset of this storm period, and the discharge could only be reduced by 20,000 cfs per day. Consequently, by the time Arrow had reduced to its minimum release, the lower river was near its peak. Heavy local runoff into Bonneville produced a peak daily regulated inflow of 392,000 cfs on 25 February but rapid drawdown of the Bonneville pool on 24 February provided storage to control the peak outflow to 355,000 cfs. The observed peak stage at Vancouver, Washington was 18.5 feet and the unregulated stage would have been 22.9 feet, flood stage is 16.0 feet. After stages in the lower Columbia River returned to normal, the Treaty projects resumed drafting towards their spring flood control targets.

Flood control during the spring runoff was provided by the normal refill operation of the Treaty reservoirs and other storage reservoirs in the Columbia River Basin. Daily flood control conditions were issued between 28 May and 20 June. The observed and unregulated hydrographs for the Columbia River at The Dalles between 1 July 1985 and 31 July 1986 are shown on Chart 13 along with a summary hydrograph of historical flows. As shown on Chart 14, the unregulated peak flow at The Dalles would have been 719,000 cfs on 4 and 5 June and it was controlled to a maximum of 388,000 cfs on 3 June. Chart 14 also shows the effect of Mica, Arrow, Duncan, and Libby regulations on the flow at The Dalles.

The observed peak stage at Vancouver, Washington was 12.5 feet and the unregulated stage would have been 24.4 feet. Chart 15 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the regulation of these two reservoirs to guidelines in the Treaty Flood Control Operating Plan.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made periodically as usual before and during the 1986 spring runoff season in accord with the Treaty Flood Control Operating Plan. The results of these computations started out on 1 January 1986 at 300,000 cfs then decreased to 275,000 cfs on 1 February, increased to 330,000 cfs on 1 March, and decreased again to 315,000 cfs on 1 April and 305,000 cfs on 1 May. Data for the 1 May ICF computation are given in Table 6.

Table 1

Unregulated Runoff Volume Forecasts
Millions of Acre-Feet
1986

Forecast Date - 1st of	DUNCAN Most Probable 1 April-31 August	ARROW Most Probable 1 January-31 August	MICA Most Probable 1 April-31 August	LIBBY Most Probable 1 April-31 August	UNREGULATED RUNOFF COLUMBIA RIVER AT THE DALLES, OREGON Most Probable 1 January-31 July
January	1.9	22.5	12.1	6.5	96.8
February	2.0	23.4	12.1	6.0	93.3
March	2.1	24.1	12.5	6.1	103.0
April	2.1	24.3	12.5	5.8	106.0
May	2.2	24.7	12.2	5.9	108.0
June	2.2	23.8	12.1	6.1	108.0
Actual	2.1	23.4	11.9	6.1	108.3

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

Table 2

95 Percent Confidence Forecast and Variable Energy Content Curve Mica 1986

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		5044.0	5024.0	5213.1	5234.4	5078.4	5064.9
2 95% FORECAST ERROR, KSFD		665.8	537.9	498.3	485.6	457.9	448.9
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		4378.2	4486.1	4714.8	4748.8	4620.5	4616.0
4 OBSERVED FEB 1 - DATE INFLOW, KSFD				113.8	259.5	486.7	1384.0
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		4378.2	4486.1	4601.0	4489.3	4133.8	3232.0
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		4378.2					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		2180.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		1331.0					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		2424.9					
JAN 31 ECC, FT [7]		2424.9					
BASE ECC, FT	2436.4						
LOWER LIMIT, FT	2406.4						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		4286.3	4391.9				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1760.0	1760.0				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		1002.9	897.3				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		2417.6	2415.2				
FEB 28 ECC, FT [7]		2417.6	2415.2				
BASE ECC, FT	2422.9						
LOWER LIMIT, FT	2398.1						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.6	95.6	97.7			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		4185.6	4288.7	4495.2			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1295.0	1295.0	1295.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		638.6	535.5	329.0			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		2409.2	2406.8	2401.8			
MAR 31 ECC, FT [7]		2409.2	2406.8	2401.8			
BASE ECC, FT	2414.6						
LOWER LIMIT, FT	2393.8						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		91.0	91.0	93.0	95.2		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		3984.2	4082.3	4278.9	4273.8		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		920.0	920.0	920.0	920.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		465.0	366.9	170.3	175.4		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		2405.1	2402.8	2398.0	2398.1		
APR 30 ECC, FT [7]		2405.1	2402.8	2398.0	2398.1		
BASE ECC, FT	2407.9						
LOWER LIMIT, FT	2393.8						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		73.7	73.7	75.3	77.1	81.0	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		3226.7	3306.3	3464.6	3461.2	3348.4	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		610.0	610.0	610.0	610.0	610.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		912.5	832.9	674.6	678.0	790.8	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		2415.5	2413.7	2410.0	2410.1	2412.7	
MAY 31 ECC, FT [7]		2413.3	2413.3	2410.0	2410.1	2412.7	
BASE ECC, FT	2415.1						
LOWER LIMIT, FT	2393.8						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		36.5	36.5	37.3	38.2	40.1	49.0
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		1598.0	1637.4	1716.2	1714.9	1657.7	1599.8
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		310.0	310.0	310.0	310.0	310.0	310.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		2241.2	2201.8	2123.0	2124.3	2181.5	2239.4
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		2444.3	2443.5	2441.9	2441.9	2443.1	2444.3
JUN 30 ECC, FT [7]		2443.0	2443.0	2441.9	2441.9	2443.0	2443.0
BASE ECC, FT	2447.6						
LOWER LIMIT, FT	2393.8						
JUL 31 ECC, FT	2469.8	2469.8	2469.8	2469.8	2469.8	2469.8	2469.8

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3529.2 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT (USABLE STORAGE)
6 FROM RESERVOIR ELEVATION STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR

Table 3

95 Percent Confidence Forecast and Variable Energy Content Curve Arrow 1986

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		9833.5	10211.6	10588.3	10905.0	11037.9	10701.3
2 95% FORECAST ERROR, KSFD		1571.1	1246.9	1089.3	925.3	844.0	856.3
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		8262.4	8964.7	9499.0	9979.7	10193.9	9845.0
4 OBSERVED FEB 1 - DATE INFLOW, KSFD		0.0	0.0	331.6	805.4	1526.0	3737.9
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		8262.4	8964.7	9167.4	9174.3	8667.9	6107.1
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		8262.4					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		1454.0					
MICA REFILL REQUIREMENTS, KSFD [9]		2198.2					
MIN. JAN 31 RESERVOIR CONTENTS, KSFD [5]		0.0					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		1377.9					
JAN 31 ECC, FT [7]		1387.2					
BASE ECC, FT	1410.2						
LOWER LIMIT, FT	1387.2						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.5	97.5				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		8055.8	8740.6				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		1314.0	1314.0				
MICA REFILL REQUIREMENTS, KSFD [9]		2526.3	2631.9				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		0.0	0.0				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		1377.9	1377.9				
FEB 28 ECC, FT [7]		1380.4	1380.4				
BASE ECC, FT	1417.9						
LOWER LIMIT, FT	1380.4						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		94.7	94.7	97.1			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		7824.5	8489.6	8901.5			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		1159.0	1159.0	1159.0			
MICA REFILL REQUIREMENTS, KSFD [9]		2890.6	2993.7	3200.2			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		0.0	0.0	0.0			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		1377.9	1377.9	1377.9			
MAR 31 ECC, FT [7]		1377.9	1377.9	1377.9			
BASE ECC, FT	1425.6						
LOWER LIMIT, FT	1377.9						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		88.4	88.4	90.7	93.4		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		7304.0	7924.8	8314.8	8568.8		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		1009.0	1009.0	1009.0	1009.0		
MICA REFILL REQUIREMENTS, KSFD [9]		3064.2	3162.4	3358.9	3353.8		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		348.8	0.0	0.0	0.0		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		1386.1	1377.9	1377.9	1377.9		
APR 30 ECC, FT [7]		1386.1	1377.9	1377.9	1377.9		
BASE ECC, FT	1427.2						
LOWER LIMIT, FT	1377.9						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		67.6	67.6	69.4	71.4	76.5	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		5585.4	6060.1	6362.2	6550.4	6630.9	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		854.0	854.0	854.0	854.0	854.0	
MICA REFILL REQUIREMENTS, KSFD [9]		2714.4	2714.4	2854.6	2851.3	2738.4	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		1562.6	1087.8	926.0	734.4	541.0	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		1410.4	1401.5	1398.3	1394.4	1390.4	
MAY 31 ECC, FT [7]		1410.4	1401.5	1398.3	1394.4	1390.4	
BASE ECC, FT	1434.9						
LOWER LIMIT, FT	1377.9						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		31.4	31.4	32.2	33.1	35.5	46.4
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		2594.4	2814.9	2951.9	3036.7	3077.1	2833.7
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		434.0	434.0	434.0	434.0	434.0	434.0
MICA REFILL REQUIREMENTS, KSFD [9]		1352.6	1352.6	1406.2	1404.9	1352.6	1352.6
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		2771.8	2551.3	2467.9	2381.8	2289.1	2532.5
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		1431.3	1427.7	1426.3	1424.8	1423.3	1427.4
JUN 30 ECC, FT [7]		1431.3	1427.7	1426.3	1426.3	1424.8	1427.4
BASE ECC, FT	1444.0						
LOWER LIMIT, FT	1377.9						
JUL 31 ECC, FT	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (3579.6 KSFD) PLUS TWO PRECEDING LINES LESS LINE PRECEDING THAT
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973.
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR
8 FOR ARROW LOCAL: MICA MINIMUM POWER DISCHARGES.
9 FOR ARROW TOTAL: MICA FULL CONTENT LESS ENERGY CONTENT CURVE

Table 4

95 Percent Confidence Variable Energy Content Curve Duncan 1986

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE FEB 1 - JUL 31 INFLOW, KSFD [1]		828.7	871.9	909.9	912.1	980.4	962.4
2 95% FORECAST ERROR, KSFD		154.1	118.6	113.5	105.6	95.4	94.0
3 95% CONFIDENCE FEB 1 - JUL 31 INFLOW, KSFD [2]		674.6	753.3	796.4	806.5	885.0	868.4
4 OBSERVED FEB 1 - DATE INFLOW, KSFD				18.2	51.2	109.7	322.4
5 RESIDUAL 95% DATE - JUL 31 INFLOW, KSFD [3]		674.6	753.3	778.2	755.3	775.3	546.0
ASSUMED FEB 1 - JUL 31 INFLOW, % OF VOLUME		100.0					
ASSUMED FEB 1 - JUL 31 INFLOW, KSFD [4]		674.6					
MIN. FEB 1 - JUL 31 OUTFLOW, KSFD		18.1					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		49.3					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		1804.8					
JAN 31 ECC, FT [7]		1804.8					
BASE ECC, FT	1833.6						
LOWER LIMIT, FT	1794.7						
ASSUMED MAR 1 - JUL 31 INFLOW, % OF VOLUME		97.9	97.9				
ASSUMED MAR 1 - JUL 31 INFLOW, KSFD [4]		660.4	737.5				
MIN. MAR 1 - JUL 31 OUTFLOW, KSFD		15.3	15.3				
MIN. FEB 28 RESERVOIR CONTENT, KSFD [5]		60.7	0.0				
MIN. FEB 28 RESERVOIR ELEVATION, FT [6]		1806.9	1794.2				
FEB 28 ECC, FT [7]		1806.9	1794.2				
BASE ECC, FT	1834.9						
LOWER LIMIT, FT	1794.2						
ASSUMED APR 1 - JUL 31 INFLOW, % OF VOLUME		95.5	95.5	97.5			
ASSUMED APR 1 - JUL 31 INFLOW, KSFD [4]		644.2	719.4	758.7			
MIN. APR 1 - JUL 31 OUTFLOW, KSFD		12.2	12.2	12.2			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		73.8	0.0	0.0			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		1809.2	1794.2	1794.2			
MAR 31 ECC, FT [7]		1809.2	1794.2	1794.2			
BASE ECC, FT	1836.9						
LOWER LIMIT, FT	1794.2						
ASSUMED MAY 1 - JUL 31 INFLOW, % OF VOLUME		90.1	90.1	92.0	94.3		
ASSUMED MAY 1 - JUL 31 INFLOW, KSFD [4]		607.8	678.7	715.9	712.2		
MIN. MAY 1 - JUL 31 OUTFLOW, KSFD		9.2	9.2	9.2	9.2		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		107.2	36.3	0.0	2.8		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		1814.8	1802.3	1794.2	1794.9		
APR 30 ECC, FT [7]		1814.8	1802.3	1794.2	1794.9		
BASE ECC, FT	1833.8						
LOWER LIMIT, FT	1794.2						
ASSUMED JUN 1 - JUL 31 INFLOW, % OF VOLUME		69.7	69.7	71.2	73.0	77.4	
ASSUMED JUN 1 - JUL 31 INFLOW, KSFD [4]		470.2	525.0	554.1	551.4	600.1	
MIN. JUN 1 - JUL 31 OUTFLOW, KSFD		6.1	6.1	6.1	6.1	6.1	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		241.7	186.9	157.8	160.5	111.8	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		1834.9	1827.1	1822.8	1823.2	1815.6	
MAY 31 ECC, FT [7]		1834.9	1827.1	1822.8	1823.2	1815.6	
BASE ECC, FT	1848.3						
LOWER LIMIT, FT	1794.2						
ASSUMED JUL 1 - JUL 31 INFLOW, % OF VOLUME		32.4	32.4	33.1	33.9	36.0	46.5
ASSUMED JUL 1 - JUL 31 INFLOW, KSFD [4]		218.6	244.1	257.6	256.0	279.1	253.9
MIN. JUL 1 - JUL 31 OUTFLOW, KSFD		3.1	3.1	3.1	3.1	3.1	3.1
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		490.3	464.8	451.3	452.9	429.8	455.0
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		1867.0	1863.9	1862.2	1862.4	1859.5	1862.7
JUN 30 ECC, FT [7]		1867.0	1863.9	1862.2	1862.4	1859.5	1862.7
BASE ECC, FT	1871.9						
LOWER LIMIT, FT	1794.2						
JUL 31 ECC, FT	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

1 DEVELOPED BY CANADIAN ENTITY
2 LINE 1 - LINE 2
3 LINE 3 - LINE 4
4 PRECEDING LINE X LINE 5
5 FULL CONTENT (705.8 KSFD) PLUS PRECEDING LINE LESS LINE PRECEDING THAT
6 FROM RESERVOIR ELEVATION - STORAGE CONTENT TABLE DATED FEBRUARY 21, 1973
7 LOWER OF ELEVATION ON PRECEDING LINE OR ELEVATION DETERMINED PRIOR TO YEAR

Table 5

95 Percent Confidence Forecast and Variable Energy Content Curve Libby 1986

	INITIAL	JAN 1 TOTAL	FEB 1 TOTAL	MAR 1 TOTAL	APR 1 TOTAL	MAY 1 TOTAL	JUN 1 TOTAL
1 PROBABLE JAN 1 – JUL 31 INFLOW, KSFD		3297.2	3057.2	3130.7	3084.3	3130.6	3218.5
2 95% FORECAST ERROR, KSFD		877.2	598.8	546.6	495.1	414.7	348.4
3 OBSERVED JAN 1 – DATE INFLOW, KSFD			105.3	210.0	406.7	707.1	1533.6
4 95% CONF. DATE – JUL 31 INFLOW, KSFD [1]		2420.0	2353.1	2383.1	2182.5	2008.9	
ASSUMED FEB 1 – JUL 31 INFLOW, % OF VOLUME		97.1					
ASSUMED FEB 1 – JUL 31 INFLOW, KSFD [2]		2350.8					
FEB MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0					
MIN. FEB 1 – JUL 31 OUTFLOW, KSFD [4]		543.0					
MIN. JAN 31 RESERVOIR CONTENT, KSFD [5]		702.7					
MIN. JAN 31 RESERVOIR ELEVATION, FT [6]		2357.1					
JAN 31 ECC, FT [7]		2357.1					
BASE ECC, FT	2407.2						
LOWER LIMIT, FT	2338.3						
ASSUMED MAR 1 – JUL 31 INFLOW, % OF VOLUME		94.5	97.3				
ASSUMED MAR 1 – JUL 31 INFLOW, KSFD [4]		2286.2	2288.4				
MAR MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0				
MIN. MAR 1 – JUL 31 OUTFLOW, KSFD		459.0	459.0				
MIN. FEB 1 RESERVOIR CONTENT, KSFD [5]		683.3	681.1				
MIN. FEB 1 RESERVOIR ELEVATION, FT [6]		2355.5	2355.4				
FEB 28 ECC, FT [7]		2355.5	2355.4				
BASE ECC, FT	2405.7						
LOWER LIMIT, FT	2303.7						
ASSUMED APR 1 – JUL 31 INFLOW, % OF VOLUME		91.2	93.9	96.6			
ASSUMED APR 1 – JUL 31 INFLOW, KSFD [4]		2208.0	2210.0	2301.6			
APR MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0			
MIN. APR 1 – JUL 31 OUTFLOW, KSFD		366.0	366.0	366.0			
MIN. MAR 31 RESERVOIR CONTENT, KSFD [5]		668.5	666.5	574.9			
MIN. MAR 31 RESERVOIR ELEVATION, FT [6]		2354.3	2354.2	2346.4			
MAR 31 ECC, FT [7]		2354.3	2354.2	2346.4			
BASE ECC, FT	2404.4						
LOWER LIMIT, FT	2288.1						
ASSUMED MAY 1 – JUL 31 INFLOW, % OF VOLUME		83.2	85.7	88.1	91.2		
ASSUMED MAY 1 – JUL 31 INFLOW, KSFD [4]		2013.7	2015.4	2099.1	1990.5		
MAY MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0	3000.0		
MIN. MAY 1 – JUL 31 OUTFLOW, KSFD		276.0	276.0	276.0	276.0		
MIN. APR 30 RESERVOIR CONTENT, KSFD [5]		772.8	771.1	687.4	796.0		
MIN. APR 30 RESERVOIR ELEVATION, FT [6]		2362.7	2362.6	2355.9	2364.5		
APR 30 ECC, FT [7]		2362.7	2362.6	2355.9	2364.5		
BASE ECC, FT	2403.0						
LOWER LIMIT, FT	2287.0						
ASSUMED JUN 1 – JUL 31 INFLOW, % OF VOLUME		56.9	57.5	59.1	61.2	67.1	
ASSUMED JUN 1 – JUL 31 INFLOW, KSFD [4]		1376.0	1353.0	1409.2	1336.1	1348.5	
JUN MINIMUM FLOW REQUIREMENT, CFS [3]		3000.0	3000.0	3000.0	3000.0	3000.0	
MIN. JUN 1 – JUL 31 OUTFLOW, KSFD		183.0	183.0	183.0	183.0	183.0	
MIN. MAY 31 RESERVOIR CONTENT, KSFD [5]		1317.5	1340.5	1284.3	1357.3	1345.0	
MIN. MAY 31 RESERVOIR ELEVATION, FT [6]		2400.0	2401.4	2398.0	2402.4	2401.6	
MAY 31 ECC, FT [7]		2400.0	2401.4	2398.0	2402.4	2401.6	
BASE ECC, FT	2427.0						
LOWER LIMIT, FT	2287.0						
ASSUMED JUL 1 – JUL 31 INFLOW, % OF VOLUME		19.4	20.0	20.5	21.3	23.3	34.7
ASSUMED JUL 1 – JUL 31 INFLOW, KSFD [4]		469.7	470.1	489.5	464.2	468.5	464.3
JUN MINIMUM FLOW REQUIREMENT, CFS [3]		2283.7	2240.9	2030.1	2307.4	3557.6	5132.9
MIN. JUL 1 – JUL 31 OUTFLOW, KSFD		93.0	93.0	93.0	93.0	93.0	93.0
MIN. JUN 30 RESERVOIR CONTENT, KSFD [5]		2133.8	2133.3	2114.0	2139.3	2135.0	2139.2
MIN. JUN 30 RESERVOIR ELEVATION, FT [6]		2441.9	2441.9	2441.0	2442.2	2442.0	2442.2
JUN 30 ECC, FT [7]		2441.9	2441.9	2441.0	2442.2	2442.0	2442.2
BASE ECC, FT	2452.5						
LOWER LIMIT, FT	2287.0						
JUL 31 ECC, FT		2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN 1 – JUL 31 FORECAST, EARLYBIRD, MAF [8]		95.1	95.1	104.0	104.0	107.0	111.0

1 LINE 1 – LINE 2 LINE 3.
2 PRECEDING LINE TIMES LINE 4.
3 BASED ON POWER DISCHARGE REQUIREMENTS, DETERMINED FROM 8.
4 CUMULATIVE MINIMUM OUTFLOW FROM 3, FROM DATE TO JULY.
5 FULL CONTENT (2510.5 KSFD) PLUS 4, AND MINUS 2.
6 ELEVATION FROM 5, STORAGE CONTENT TABLE, DATED JUNE 1980.
7 ELEVATION FROM 6, BUT LIMITED BASE ECC, AND ECC LOWER LIMIT.
8 USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3

Table 6

Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1986

1 May Forecast of May-August Unregulated Runoff Volume, MAF		71.8
Less Estimated Depletions, MAF		1.5
Less Upstream Storage Corrections, MAF		
MICA	6.6	
ARROW	5.0	
LIBBY	3.2	
DUNCAN	1.2	
HUNGRY HORSE	.7	
FLATHEAD LAKE	.5	
NOXON	.0	
PEND OREILLE LAKE	.5	
GRAND COULEE	2.5	
BROWNLEE	.3	
DWORSHAK	.4	
JOHN DAY	.2	
TOTAL	21.1	21.1
Forecast of Adjusted Residual Runoff Volume, MAF		49.2
Computed Initial Controlled flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		310.0

Chart 1

Seasonal Precipitation Columbia River Basin October 1985 - March 1986 Percent of 1961 - 1980 Average

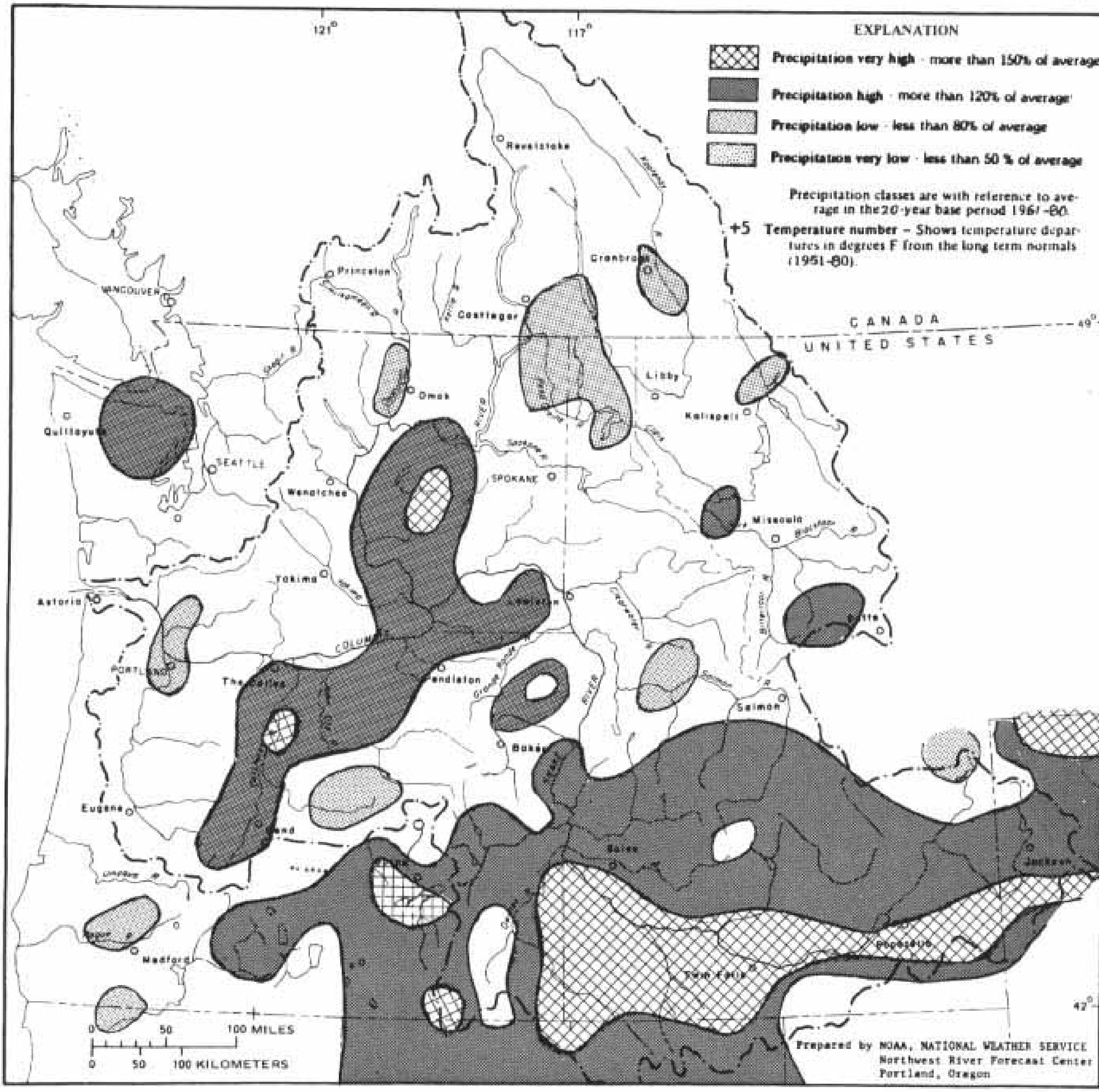


Chart 2

Columbia Basin Snowpack

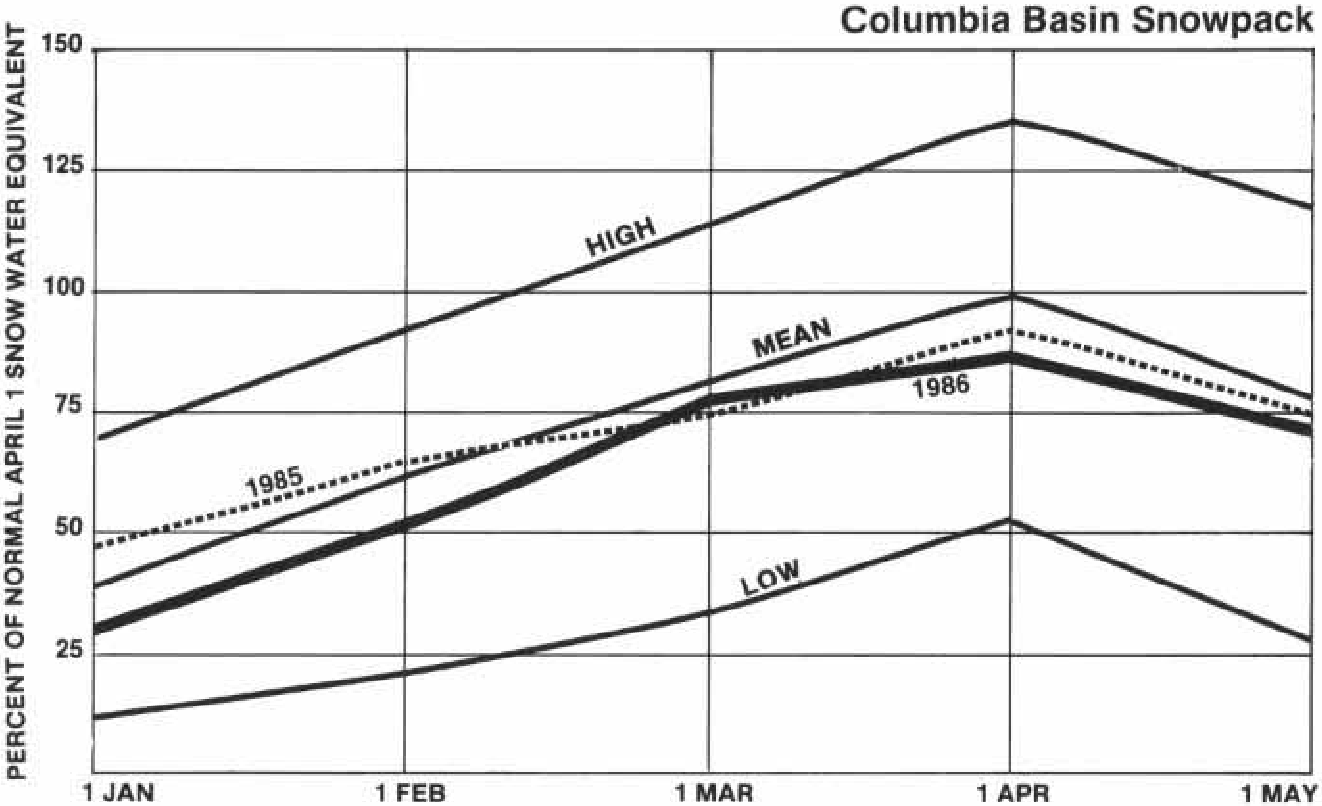


Chart 3

Winter Season
Temperature and Precipitation Index 1985 - 1986
Columbia River Basin above The Dalles

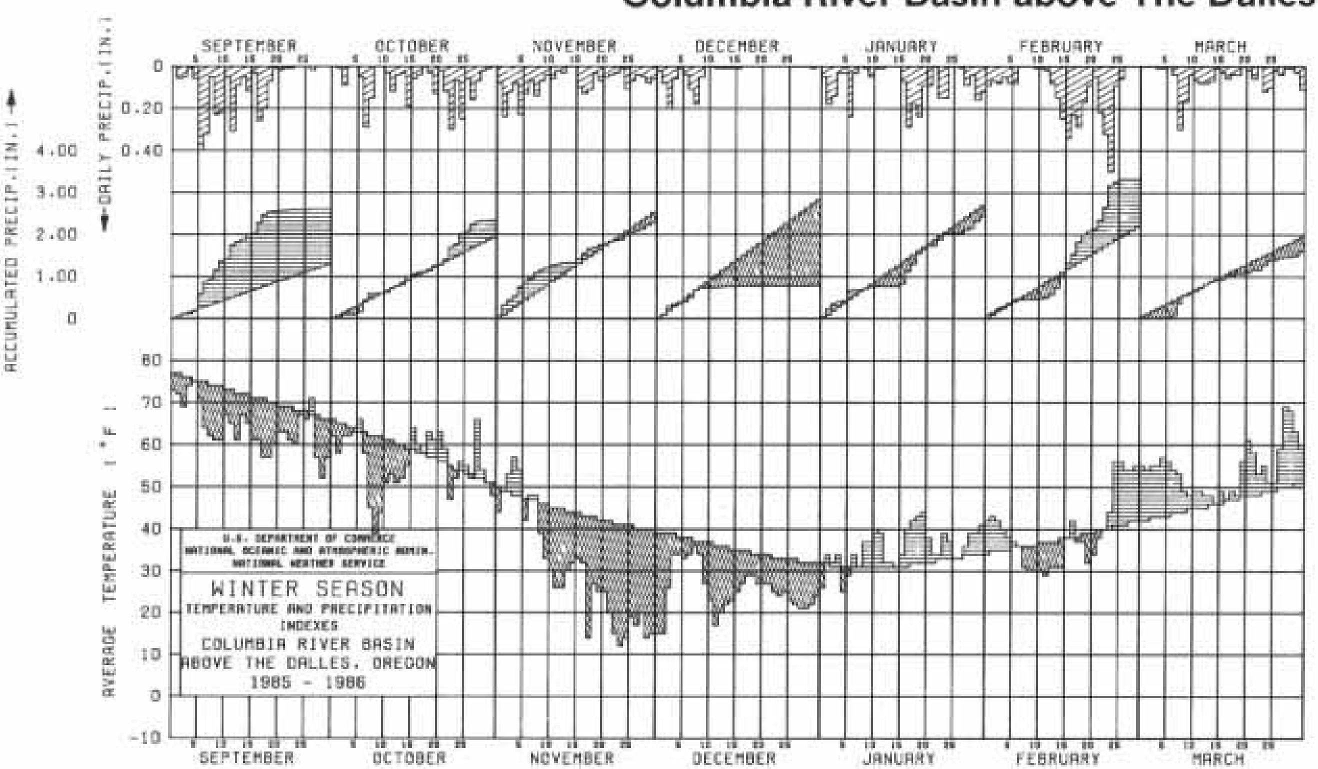


Chart 4

Snowmelt Season
Temperature and Precipitation Indexes 1985 - 1986
Columbia River Basin above The Dalles

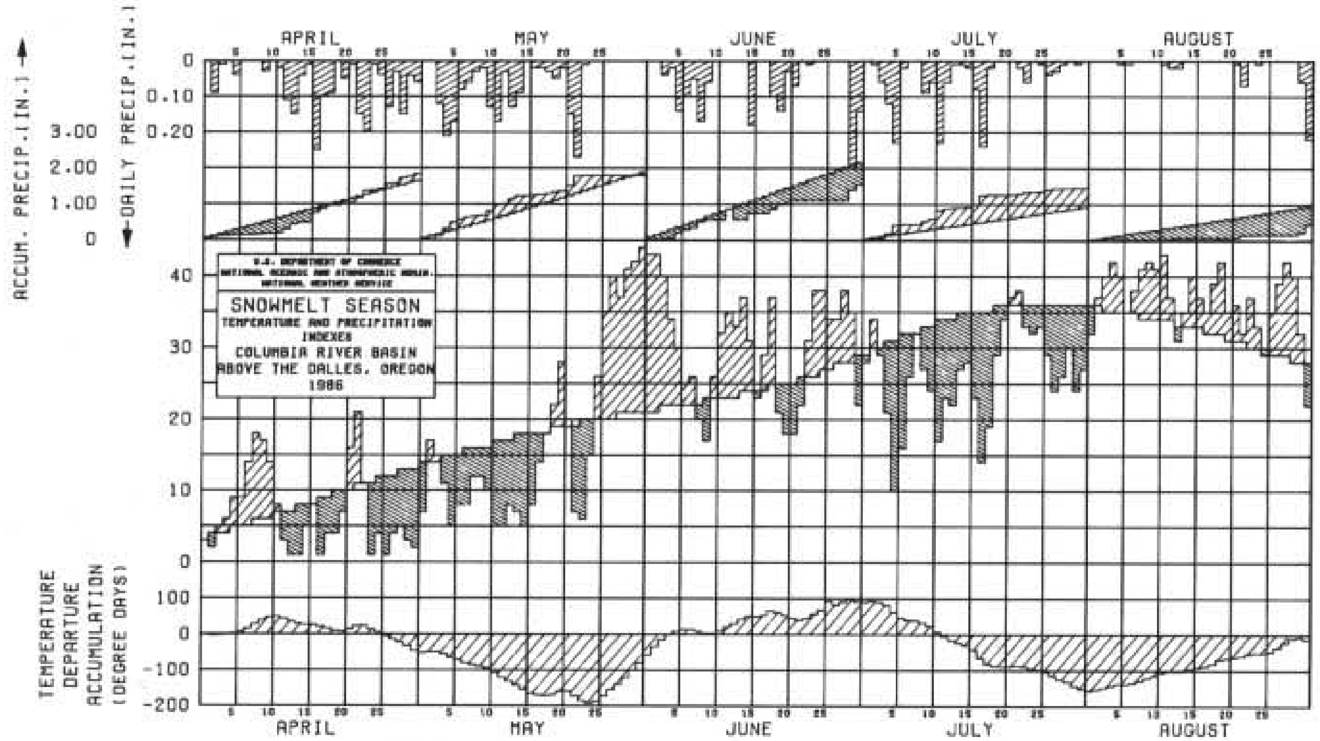


Chart 5

Snowmelt Season
Temperature and Precipitation Indexes 1985 - 1986
Columbia River Basin in Canada

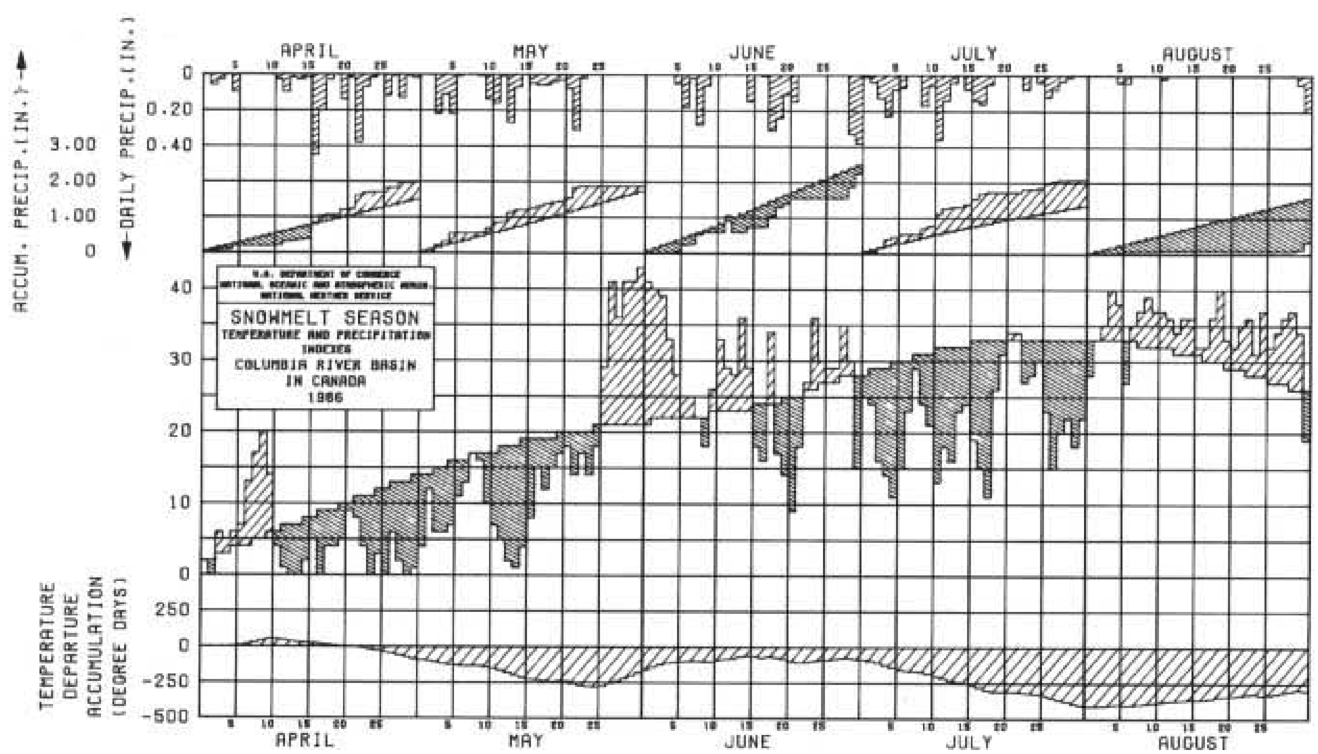


Chart 6
Regulation of Mica
1 July 1985 - 31 July 1986

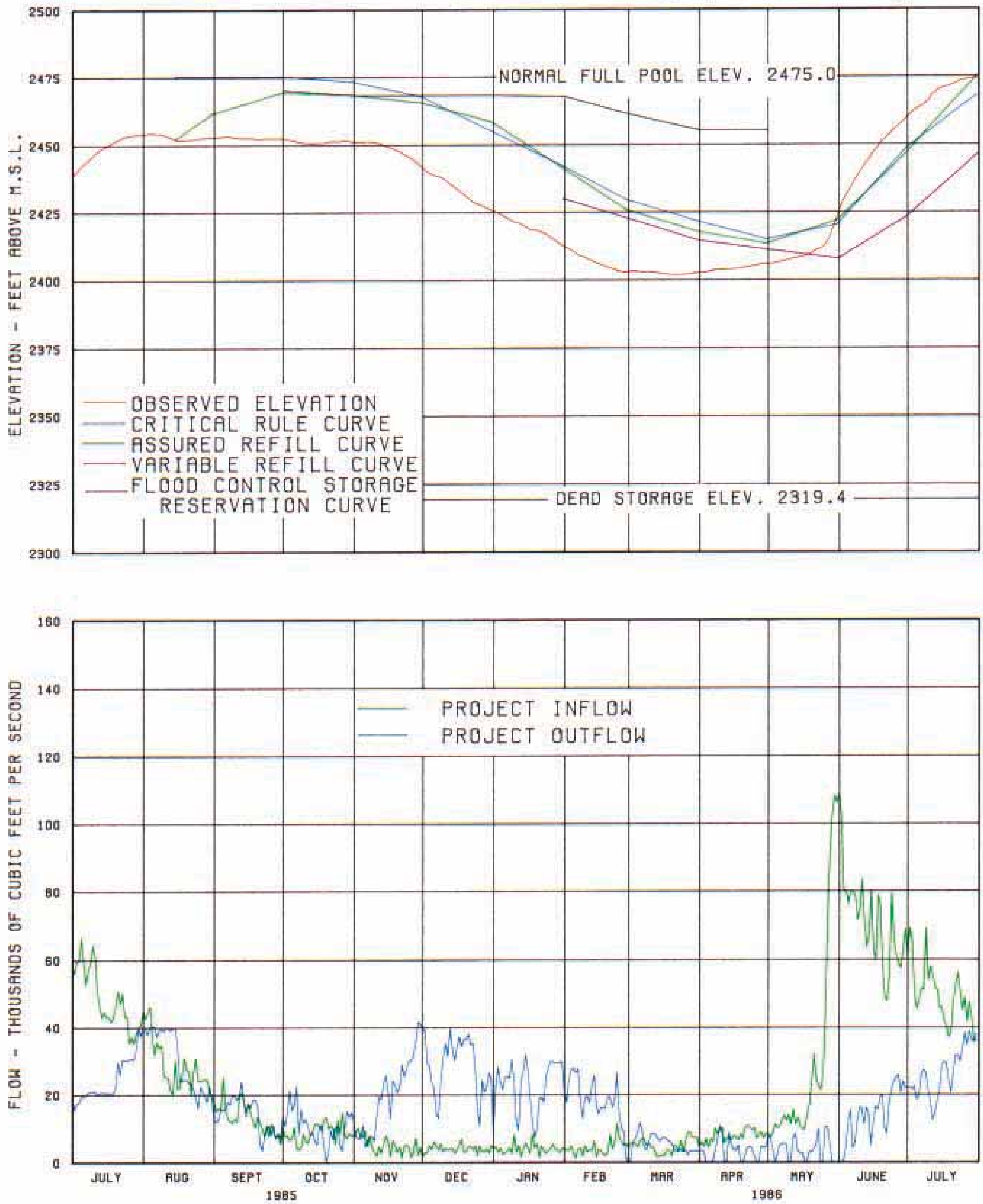


Chart 7
Regulation of Arrow
1 July 1985 - 31 July 1986

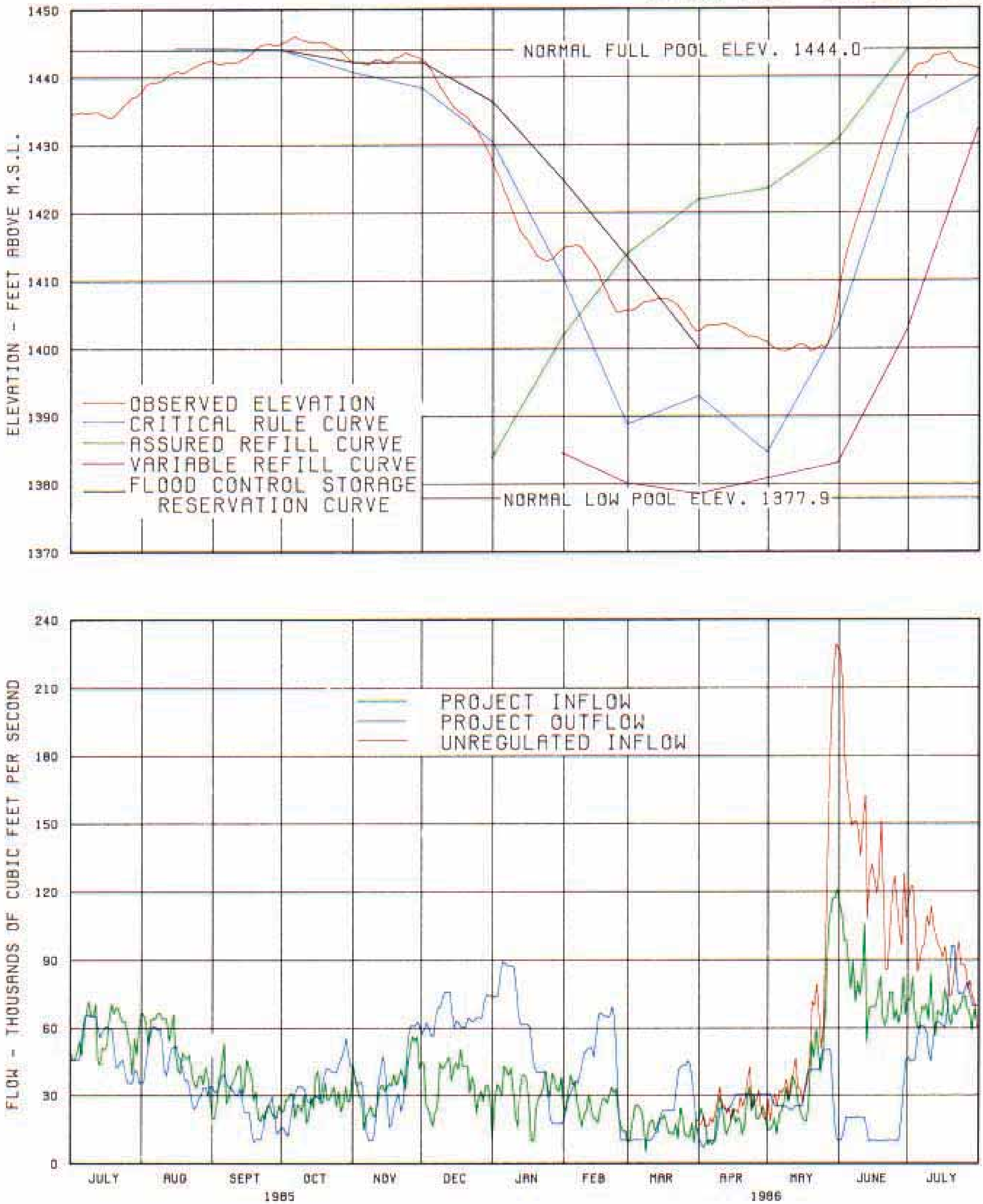
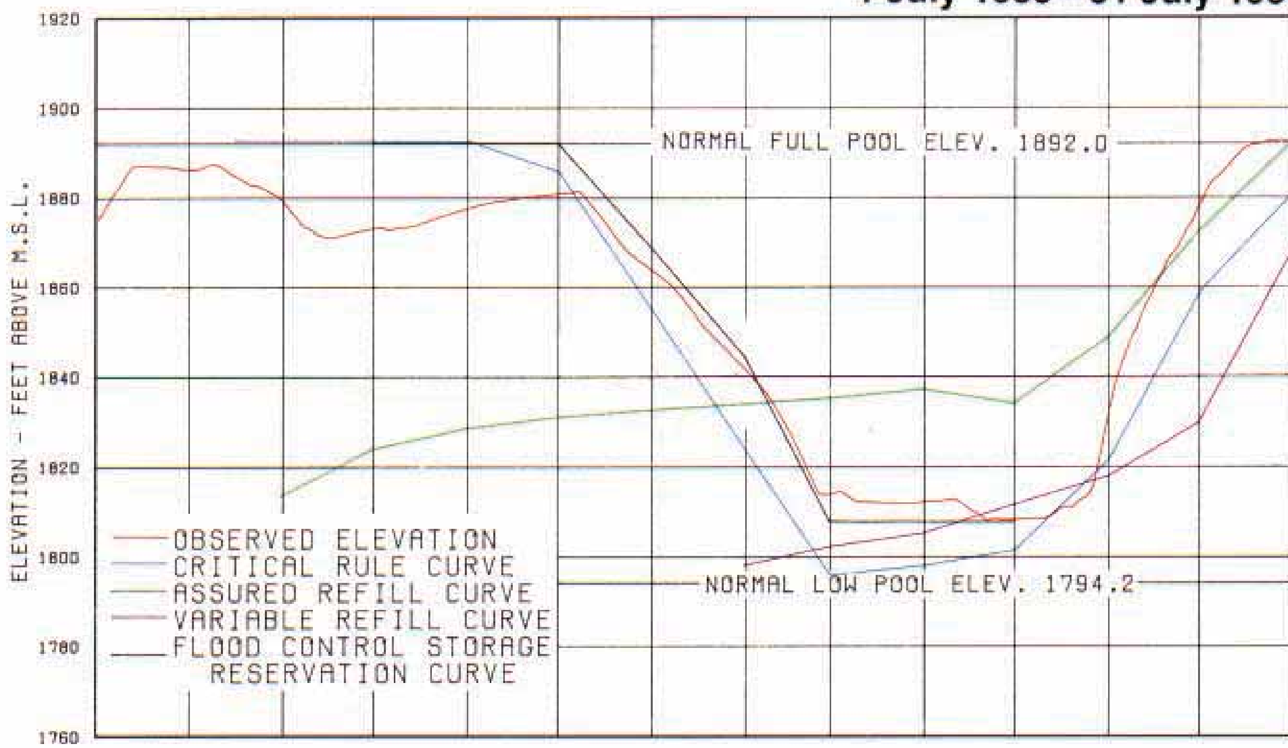


Chart 8
Regulation of Duncan
1 July 1985 - 31 July 1986



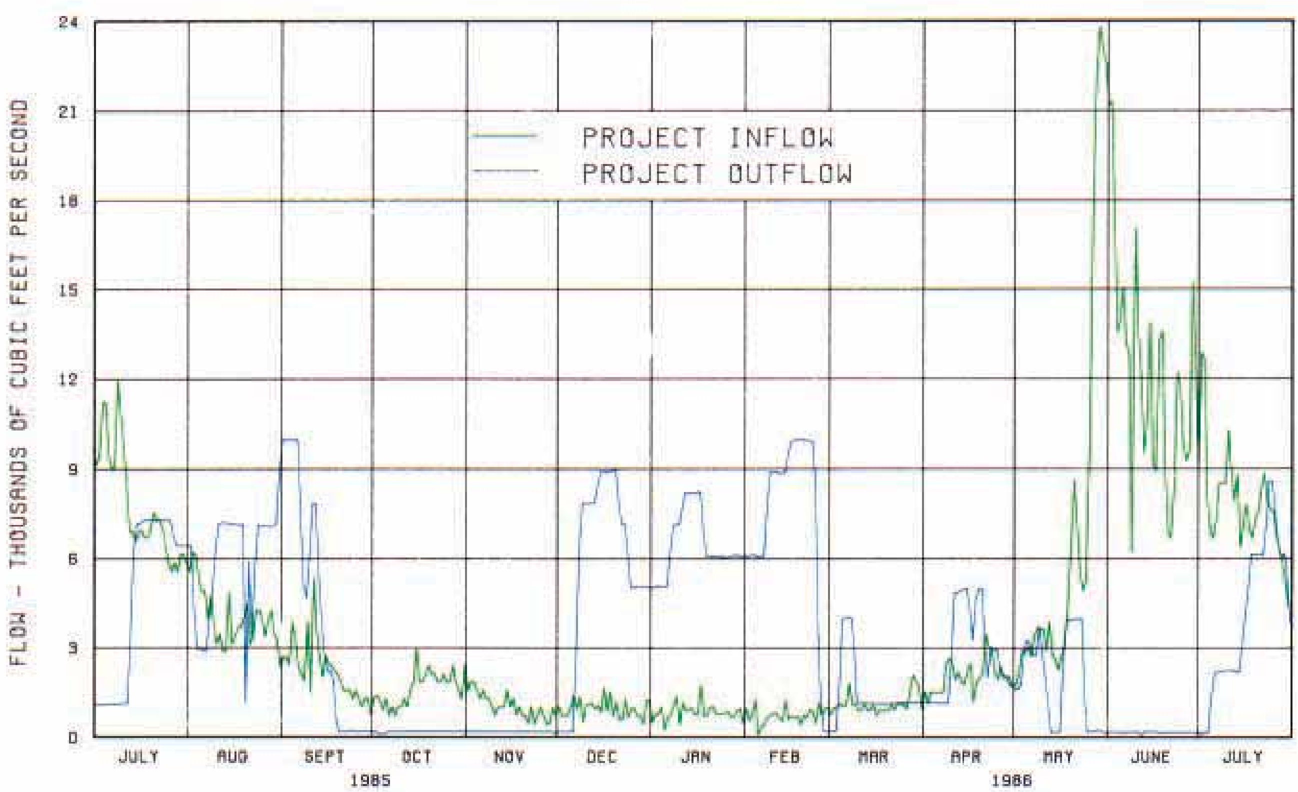


Chart 9

Regulation of Libby
1 July 1985 - 31 July 1986

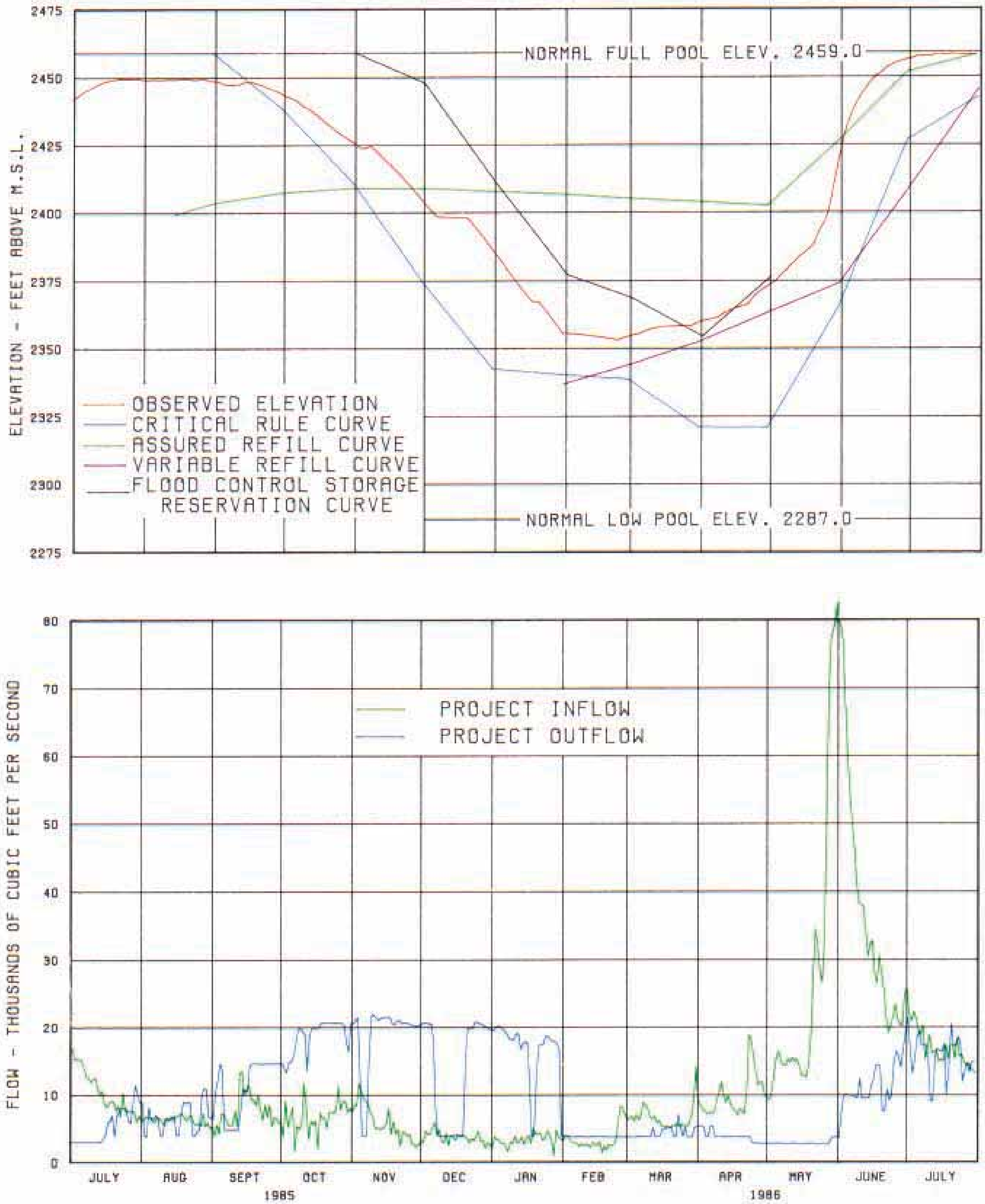


Chart 10

Regulation of Kootenay Lake 1 July 1985 - 31 July 1986

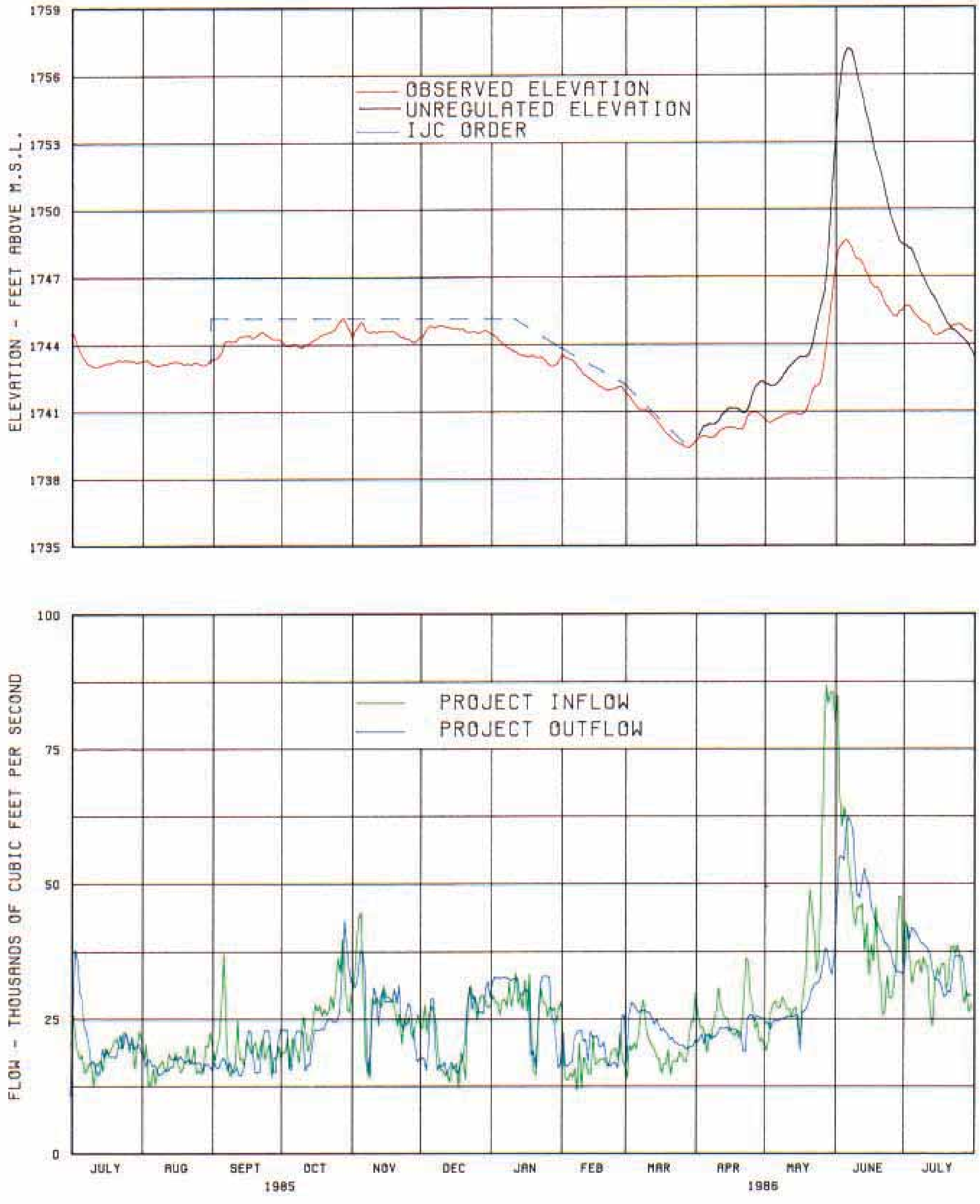


Chart 11

Columbia River at Birchbank
1 July 1985 - 31 July 1986

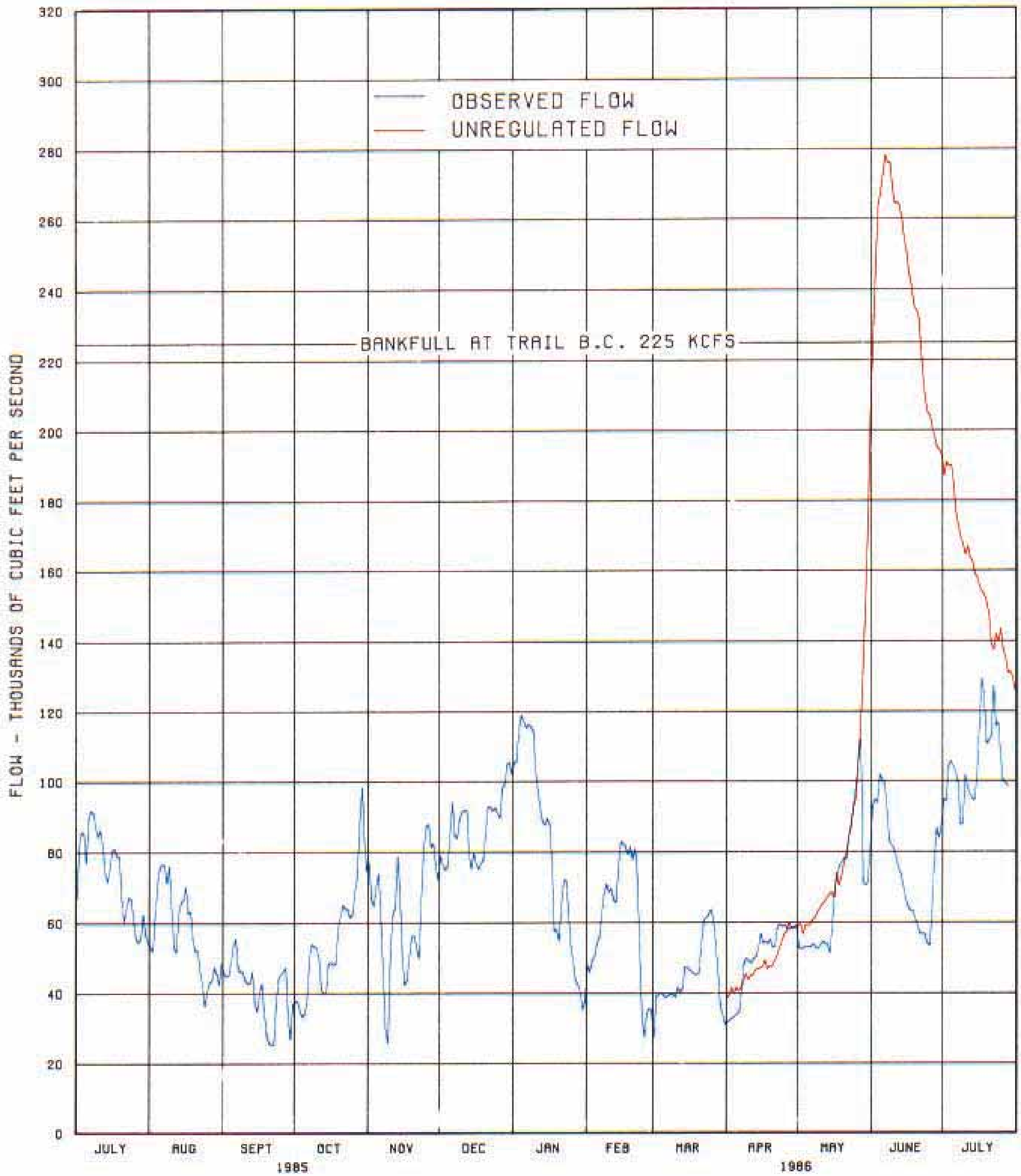
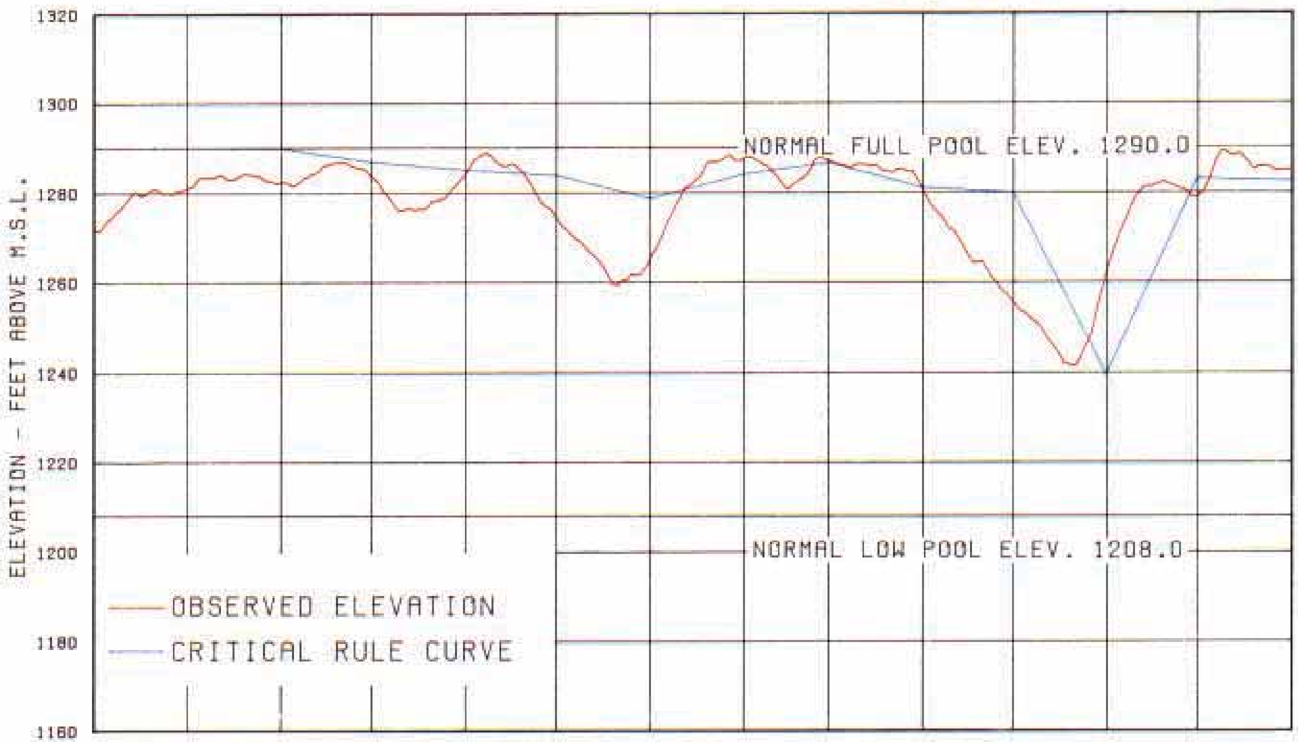


Chart 12

Regulation of Grand Coulee
1 July 1985 - 31 July 1986



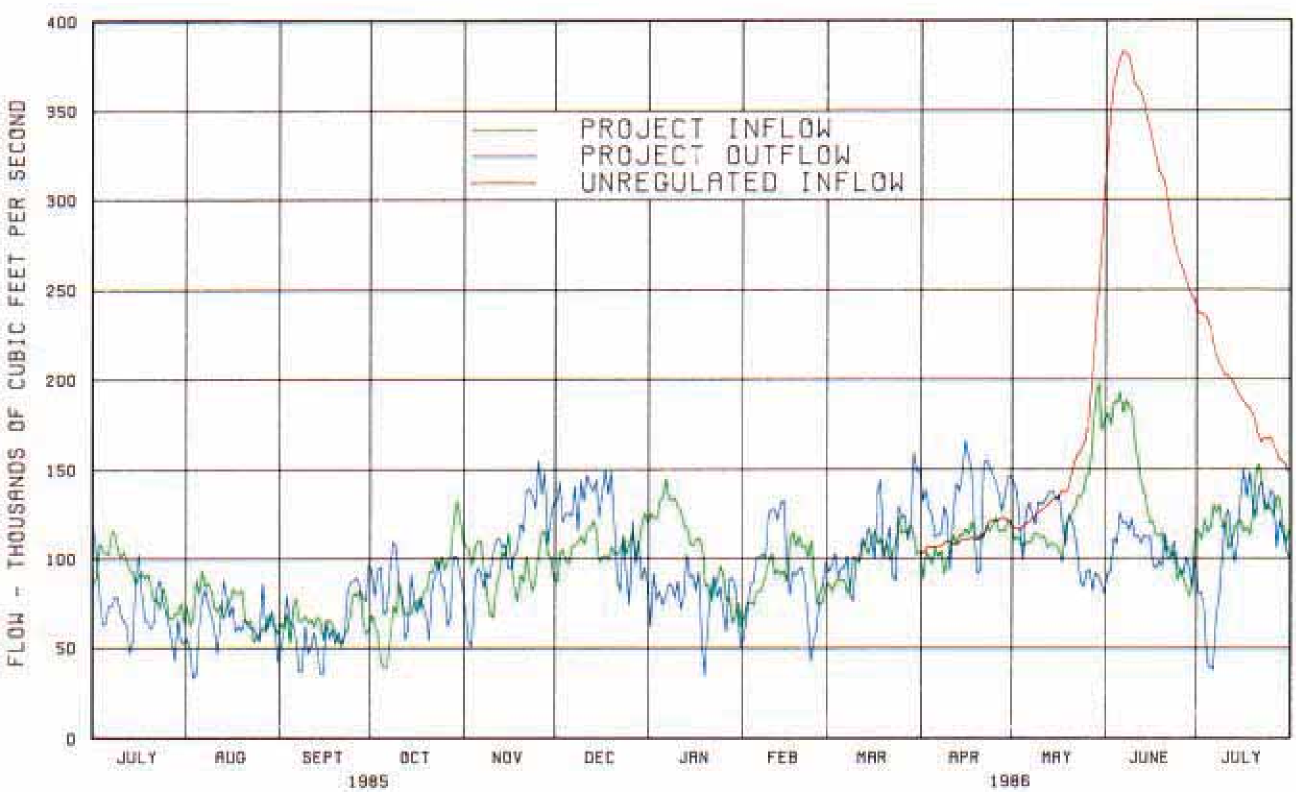


Chart 13

Columbia River at The Dalles
1 July 1985 - 31 July 1986

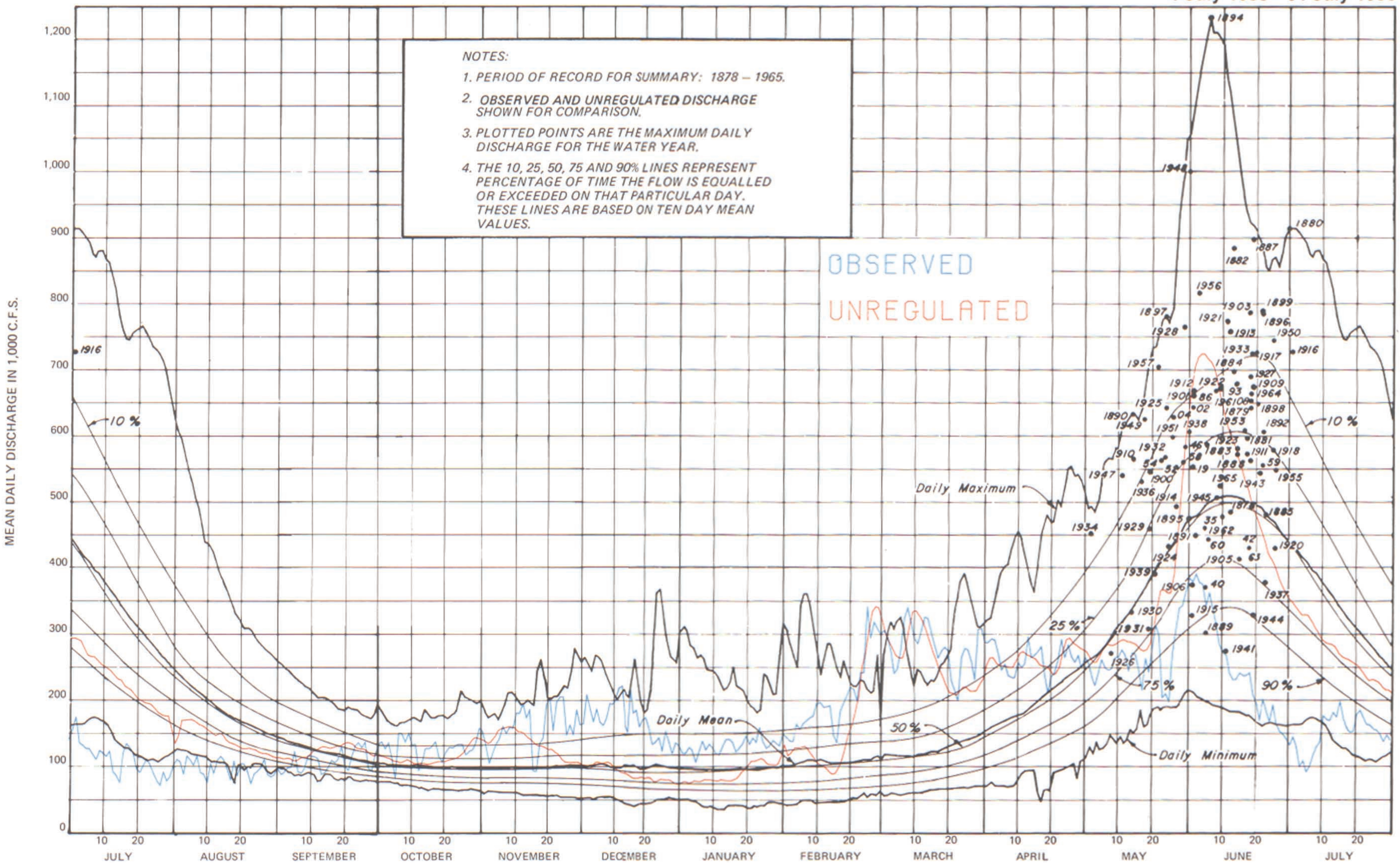


Chart 14

Columbia River at The Dalles
1 April 1986 - 31 July 1986

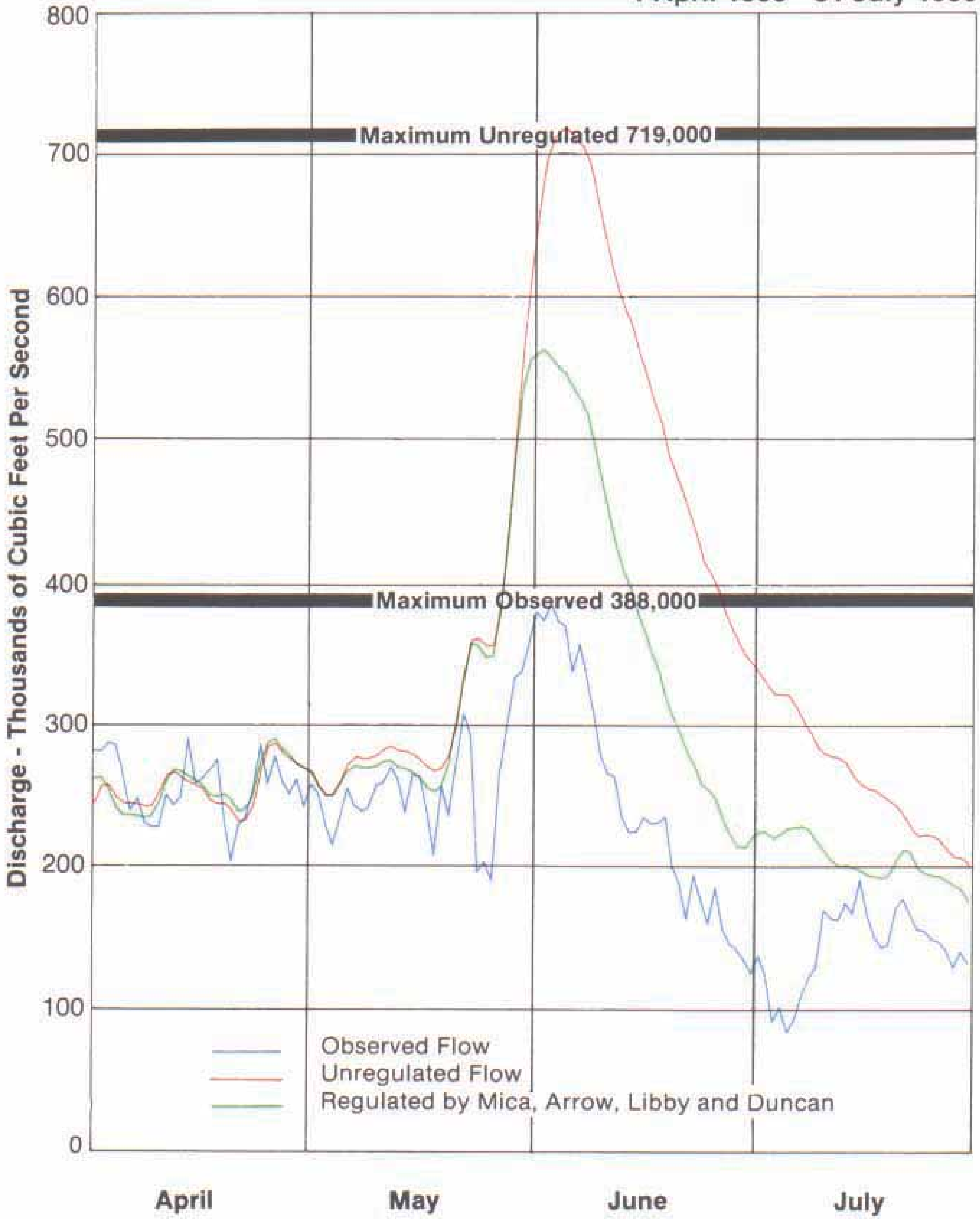


Chart 15

1986 Relative Filling
Arrow and Grand Coulee